Stephen F. Mecham (Bar No. 4089)
Stephen F. Mecham Law, PLLC
10 West 100 South, Suite 323
Salt Lake City, Utah 84101
Telephone: (385) 222-1618
Email: sfmecham@gmail.com

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	**DOCKET NO. 17-035-61** **Vivint Solar Exhibit 1SR** **Phase 2**

SURREBUTTAL TESTIMONY OF CHRISTOPHER WORLEY, PH.D.
FOR VIVINT SOLAR, INC.

September 15, 2020

/s/Christopher Worley

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, title and business address.

A. My name is Christopher Worley. My business address is 1800 W. Ashton Blvd, Lehi, Utah 84043. I am Director of Rate Design with Vivint Solar.

Q. Did you submit direct and rebuttal testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this testimony is to respond to the testimony of other parties in this case, update my recommended export credit rate, address some misconceptions that parties have, and provide a vision for Utah's solar market for the Commission to consider.

II. UPDATES TO RECOMMENDED EXPORT CREDIT VALUE

Q. What updates are you making to your recommended export credit rate?

A. Testimony filed by Vote Solar witness Dr. Michael Milligan caused me to reconsider my estimate for the capacity value of solar. Given his use of data from Vote Solar's load research study, his methodology and estimation more accurately reflect the capacity that exports from behind-the-meter solar provides to Rocky Mountain Power's ("RMP") grid. I am adopting his capacity value of 27.65%. As such, I am updating my recommended values for avoided generation capacity and avoided transmission capacity because both of those values rely on the capacity value of solar.

Additionally, upon further consideration I have decided to change my recommendation on how to best calculate the value of avoided energy. The use of a market proxy like EIM nodal prices should reflect RMP's marginal cost of energy, however, use of historical data raises some conceptual concerns. Firstly, historical prices may or may not accurately reflect future prices.

Energy markets have seen dramatic changes over the last 5-10 years with utility-scale renewables becoming cost-effective investments. Further, many states are pursuing accelerated coal generation retirements and other reductions in carbon emissions. Based on this and other market uncertainties, it is unclear that historical EIM prices are a suitable proxy for future prices. My second concern with my previous methodology is that are clear questions on how nodal prices should be averaged spatially and intertemporally. Behind-the-meter solar reduces load at or near the source. Customers throughout RMP's service territory have invested in solar, so it is unclear how to average and weight nodal prices to accurately reflect the distribution of behind-the-meter solar. Also, while I selected three years of historical data, would data from a different number of years provide a more accurate estimate? While I remain open to an avoided energy methodology that uses historical EIM prices, at this time, I cannot recommend a specific methodology to the Commission. Instead, I recommend adopting Vote Solar's avoided energy methodology that uses RMP's Official Forward Price Curve ("OFPC"). As noted in Dr. Milligan's testimony, "The market prices that comprise the OFPC represent RMP's best effort to value electricity in the trading region."[1] Dr. Milligan's analysis provides the clearest picture of the future value of energy avoided by behind-the-meter solar.

Q. How do these changes update your estimate of the value of avoided energy?

A. I adopt Vote Solar's estimate of 3.55 cents/kWh for the value of avoided energy.[2] Additionally, I adopt their estimate of 0.31 cents/kWh for the value of avoided line losses.[3]

[1] Revised Affirmative Testimony of Michael Milligan, Ph.D., lines 215-216.
[2] Revised Affirmative Testimony of Sachu Constantine, Table 1.
[3] Revised Affirmative Testimony of Sachu Constantine, Table 1.

Q. How does the updated capacity value of solar change your recommended value for avoided generation capacity?

A. In my direct testimony, I used the 2019 update to Lazard's Levelized Cost of Energy report to estimate the cost of building a new natural gas peaker, and then determined the amount of new capacity that solar avoids.[4] Recalculating using a capacity value of 27.65% gives an updated estimate of 1.46 cents/kWh.

Table 1: Calculation of avoided generation capacity

Step	Value
Capital cost ($/kW)	825
x 9.39% carrying charge	77.47
x 27.65% capacity value of solar	21.42
/ 1463 annual hours ($/kWh)	0.0146
/ 100 (cents/kWh)	1.46

Q. How are you updating your estimate of avoided transmission capacity?

A. I am updating my estimate of avoided transmission capacity in two ways. Firstly, I am using Dr. Milligan's capacity value. Secondly, I was made aware that the "NERA method" of estimating the marginal cost of transmission capacity should include transmission operation and maintenance ("O&M") expenses. Using Pacificorp's 2018 FERC Form 1 filings, I estimated a 4% general plant loader to account for overhead expenses of transmission O&M.[5] Also, I divided annual O&M expenses by peak transmission system load to estimate the annual O&M cost on a

[4] Direct Testimony of Christopher Worley, lines 185-194.

[5] Pacificorp 2018 FERC Form 1, page 206. $1.2 billion general plant in service (line 99) divided by $27.7 billion total electric plant in service (line 100) equals 4.3%

per kW basis, which I estimate at $11.41/kW.[6] The updated calculation is in Table 2, and my new estimate of avoided transmission capacity is 1.52 cents/kWh.

Table 2: Calculation of avoided transmission capacity

Step	**Value**
Marginal cost of transmission capacity ($/kW)	705
+ 4.3% general plant loader	735.3
x 9.39% carrying charge	69.05
+ $11.41 O&M cost ($/kW)	80.46
x 27.65% capacity value of solar	22.18
/ 1463 annual hours ($/kWh)	0.0152
/ 100 (cents/kWh)	1.52

Q. Can you please provide a full accounting of your recommended export credit?

A. Yes. Table 3 shows the factors that I or other parties have quantified in this case. Based on my estimates, the quantified factors sum to 9.85 cents/kWh, which is about 3.5% less than the retail rate of 10.2 cents per kWh.

Table 3: Value of export credit factors

Factor	**Value (cents/kWh)**
Avoided energy	3.55
Avoided line losses	0.31
Avoided generation capacity	1.46
Avoided transmission capacity	1.52
Avoided distribution capacity	0.52

[6] Pacificorp 2018 FERC Form 1, pages 320-323. Transmission operation ($170.5 million) plus maintenance ($36 million) equals $206.5 million. Annual O&M costs divided by transmission system peak load $206.5 million per year / 18.1 GW transmission peak load = $11.41/kW-year

Hedging value	0.19
Carbon compliance cost	2.80
Other factors (including resilience, environmental benefits, others)	not quantified
Export credit	**At least 10.35**

Q. Based on this updated export credit value, do you have any updated recommendations for the Commission?

A. In my rebuttal testimony, I recommended setting the export credit rate at the retail rate, which is currently 10.2 cents/kWh. Based on the utility-specific, quantifiable factors, I find that the value of solar exports is worth no less than 10.35 cents/kWh. Given the full range of qualitative and quantitative factors presented in testimony by the parties in this case, setting the export credit rate at 10.2 cents/kWh is reasonable.

III. MISCONCEPTIONS AND MISCHARACTERIZATIONS

Behind-the-meter solar reduces load at or near the source

Q. Is it fair to compare the value of distributed generation with wholesale market prices?

A. Some parties seem to misunderstand conceptually how behind-the-meter solar affects RMP's system and what costs it avoids. For example, OCC witness Mr. Hayet interprets Vote Solar's analysis of the Official Forward Price Curve ("OFPC") as equating the value of distributed generation with power sold into wholesale market hubs. He states "Vote Solar assumed that any exported solar energy produced could be sold in the market or alternatively, could allow RMP to avoid purchasing energy at the market hubs up to the full amount of the exported energy. Conceptually, this is a logical methodology however, it does not consider the impact of constraints, such as transmission limits in the System."[7] His statement complicates and confuses the conceptual issue of Vote Solar use of the OFPC or, as I previously suggested, using historical EIM prices for a similar purpose.

Vote Solar recommends using the OFPC as a market-based proxy for the marginal cost of avoided energy. In the absence of generation from behind-the-meter resources, system demand would be higher and RMP would have to increase generation from the marginal generating unit or purchase power from the EIM or market hub. The value of energy purchases that are avoided by behind-the-meter resources is the market price. Using the OFPC or EIM nodal prices as a proxy for the marginal cost of energy does not imply that electricity from behind-the-meter solar can be sold into market hubs or that it can be sold into the EIM. Electricity from behind-the-meter solar reduces load at or close to the source, and by reducing load, customer-sited solar reduces the need of RMP to provide more power from wholesale sources.

In fact, Mr. Hayet's discussion of transmission limits and constraints seems to run counter to his argument. He states that "relying on Vote Solar's unconstrained weighted average market hub approach would be completely unrealistic. Transmission limits are real, do constrain the actual operation of PacifiCorp's generation resources, and should be reflected in the GRID model."[8] I agree with Mr. Hayet that transmission limits are real. In the absence of the reduced load from behind-the-meter solar, RMP would increase generation at the marginal generating unit or make wholesale purchases at a market hub. RMP would need to secure and purchase transmission rights. Use of the transmission system incurs a cost, which can be high during peak times or other areas with high transmission congestion. While "transmission limits are real",

[7] Rebuttal Testimony of Philip Hayet, lines 341-346.
[8] Rebuttal Testimony of Philip Hayet, lines 392-395.

behind-the-meter solar reduces demand at or near its source, thereby reducing wholesale power purchases at market hubs and reducing congestion on the transmission system. The transmission limits and constraints discussed by Mr. Hayet are not a factor that should be considered when estimating the avoided cost of energy based on load reductions occurring at or near the source.

Behind-the-meter solar reduces demand at peak times

Q. Is solar a non-firm resource that provides no capacity value?

A. DPU witness Mr. Davis refers to behind-the-meter solar as a "non-firm" resource, suggesting that the export credit rate should not compensate for generation investment to meet system peak. "RMP has no control over customer generation. CG is not dispatchable due to its variability on a system basis. CG has no reliability requirements. CG is not required to have a contract with RMP other than its interconnection agreement. Finally, RMP has no control of when customer generation is available."[9] While Mr. Davis is correct that RMP has no control over generation on the customer side of the meter, he ignores the fact that customer investment directly impacts utility investment.

When a customer invests in behind-the-meter solar, it reduces the amount of kilowatt-hours (kWh) RMP delivers and sells to that customer. The electricity generated by the behind-the-meter system will be consumed onsite. Or if a customer's generation exceeds their load, that power will be pushed back onto the grid where it is consumed by the nearest load source, which is most likely a neighbor. The extent to which the behind-the-meter solar system generates during peak hours, it reduces load at the source or load at a neighboring house of facility. Generating at peak times reduces the need to dispatch a generator, thereby lowering requirements

[9] Phase II Rebuttal Testimony of Robert A. Davis, lines 446-450.

during peak times. The point is not that behind-the-meter systems provide "firm capacity", rather that probabilistically they reduce load during peak times, thereby slowing the need for RMP to invest in future peak capacity. Customer investment in behind-the-meter solar by end users defers peak investment by the utility, so distributed energy resources ("DERs") should be compensated for the peak capacity they avoid or defer.

Customer investment in behind-the-meter solar reduces RMP's short-run and long-run marginal costs

Q. Does RMP hold that behind-the-meter investment can defer system investment?

A. RMP witness Jacob Barker asserts that "relying on customer generation to defer capital investment places undue risk on the system."[10] He then provides an example of a substation upgrade project and estimates that a large amount of behind-the-meter solar would be needed to defer the project.[11] He then raises questions on how to ensure performance of those systems if RMP does not control the systems or have commitment from the customer for the generation to remain in service. In short, it seems RMP's position is that deferring transmission or distribution system investment using behind-the-meter resources is problematic and difficult.

Q. What is wrong with RMP's line of argument?

A. RMP is not wrong, but that is not what anyone is arguing. Based on my reading of testimony, no parties suggest that DER defer all capital investment or that DER investment is avoiding or deferring specific transmission or distribution projects. While utilities and utility regulators in some states are considering "distribution system planning" and the use of "non-

[10] Rebuttal Testimony of Jacob S. Barker, lines 40-41.
[11] Rebuttal Testimony of Jacob S. Barker, lines 52-82.

wires alternatives" to shift capital investment from transmission to DERs, that is not what parties in this case are arguing.

By reducing load at its source, it reduces the need for RMP to build generation, transmission, and distribution assets. The extent to which DER generates power during peak times, that defers or avoids the need to build additional peaking plants. Because load is reduced at the source, it incrementally defers or avoids the need to build transmission lines to address system congestion during peak times. As such, DERs should be compensated much like "deemed savings" for energy efficiency programs.[12]

RMP is wrong about subsidies and competitive markets

Q. Is RMP's assertion that subsidies reduce competition correct?

A. No. In her rebuttal testimony, Ms. Steward states: "Subsidies, by their very nature, reduce competitive forces rather than introducing them. ...True competitive benefits occur when an industry can operate without subsidies."[13] Ms. Steward is wholly wrong when she states that competitive benefits occur without subsidies. In fact, basic economic theory tells us that subsidies likely increase competition within an industry.

Competition occurs when there are many firms within an industry. Those firms will use pricing, features, brand loyalty, and other techniques to try to gain customers. Companies will invest in developing new features to excite customers and companies will invest in new processes to try to reduce cost. Customers benefit from competition because companies in competitive markets will improve their products and may offer more types of products at

[12] Evaluation, Measurement, & Verification. (n.d.). Retrieved September 15, 2020, from https://www.aceee.org/toolkit/2020/02/evaluation-measurement-verification
[13] Rebuttal Testimony of Joelle Steward, lines 124-131

different price points. In contrast, when there are few companies serving a market, the choice by customers is limited and those companies may choose to not invest in innovations that will improve customer satisfaction.

Subsidies in a competitive market increase competition simply by increasing the number of companies in the market. A good example of a market with strong competition is the fast-food hamburger market. Imagine there was a subsidy for hamburger restaurants, for example a tax credit for investing in new restaurant facilities or equipment or a subsidy on the number of hamburgers produced and sold. The subsidy would lower the marginal cost of producing hamburgers, thereby encouraging more hamburger restaurants to enter the market. A subsidy would encourage more companies to enter to compete with McDonald's, Wendy's, Sonic, Burger King, 5 Guys, and the many other hamburger chains. To differentiate themselves from existing companies, the new hamburger companies would develop new recipes and sell different kinds and qualities of burgers at different price points. Customers benefit from the choices and innovation that competition brings. Subsidies increase competition to the benefit of customers.

Ms. Steward's comments on subsidies are wrong and they are a distraction from this case. The existence of the federal solar investment tax credit (ITC) is not at issue in this case. The existence of other state and local incentives for solar is not at issue. The issue in this case is setting the compensation of excess energy. Based on estimates by Vote Solar and Vivint Solar, the benefits of excess energy exceed the costs, which means that setting compensation for excess energy at the retail rate results in no subsidy. Suggesting that doing so provides an "unfair burden on Rocky Mountain Power's customers"[14] is completely false.

[14] Rebuttal Testimony of Joelle Steward, line 119.

The core issue in the case is not a shifting of costs but rather a regulated monopoly interfering in a competitive market

Q. Is there a cost shift between solar customers and non-solar customers?

A. Ms. Steward has argued in this case that the value of exports under Schedule 135 and Schedule 136 is too high and that "[i]f export credit rates are set at a level that is above their actual value, costs are shifted to other customers and the electric rates for other customers increase." However, RMP has not presented evidence in the case that there is a cost shift among customers. Instead, RMP has cherry picked the export credit factors that suit their argument (like avoided energy, line losses) and then willfully ignores that behind-the-meter investment reduces grid investment (like generation, transmission, etc.). In fact, research by the Lawrence Berkeley National Lab conducted a broad analysis to estimate the likelihood of cost shifting from solar to non-solar customers and found that cost shifts are "imperceptible" when solar penetration is less than 10%.[15]

Q. If there is no cost shift, why has RMP pursued this case for the better part of a decade?

A. PacifiCorp presents the true motivation of this case in its Annual 10-K filing with the Securities Exchange Commission. Under the risk factors that must be disclosed to investors, PacifiCorp states:

> "A significant sustained decrease in demand for electricity or natural gas... would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its financial results. Factors that could lead to a decrease in market demand include, among others:

[15] Barose, Galen. (2017). *Putting the Potential Rate Impacts of Distributed Solar into Context.* Lawrence Berkeley National Laboratory.
See http://www.raponline.org/wp-content/uploads/2017/07/rap-lbnl-barbose-ncsl-jun-09-2017.pdf

...efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed... through various existing laws and regulations, as well as, deregulation, conservation, energy efficiency and *private generation measures and programs.*" [Emphasis added.][16]

PacifiCorp sees behind-the-meter solar as a corporate and financial risk because customers installing behind-the-meter solar reduce demand for electricity, thereby impacting its planned capital expenditures.

Q. Has RMP pursued other policies to ensure its capital expenditures?

A. Yes. Utah Solar Energy Association ("USEA") witness Ryan Evans noted that RMP successfully passed two pieces of Utah state legislation that allow them to own resources that would have otherwise been provided by private developers. In the 2018 General Session, RMP worked to pass HB 261, which gives RMP the opportunity to own solar resources larger than 2 MW, and HB 411 in the 2019 General Session allows RMP to own resources to help Utah municipalities meet climate goals.[17] It seems RMP's focus with those bills and their strategy in this case are intent on only allowing DERs in Utah that they can own and rate base.

Q. How can the Commission address the risk that behind-the-meter solar presents to RMP's planned capital expenditures?

A. In contrast to competitive markets, regulated utilities like RMP receive incentives through regulation. There is an implied regulatory compact that exists between governments and utilities. Utility companies provide service to all customers and regulatory commissions approve

[16] PacifiCorp Annual 10-K filing https://www.brkenergy.com/assets/upload/financial-filing/BHE%2012.31.19%20Form%2010-K_FINAL.pdf
[17] Rebuttal Testimony of Ryan Evans, lines 83-89.

rates that ensure the full recovery of the utility's costs and a rate of return. If PacifiCorp's true concern is a reduction in demand, which erodes revenue and leads to lost investment opportunities, then perhaps the Commission should consider incentive regulation. Many states offer incentives for utilities to operate energy efficiency programs. Those incentives include revenue decoupling, a lost revenue adjustment, or shareholder incentives like performance bonuses or higher rates of return to name a few.[18] I fully support RMP recovering all of their costs, and earning a reasonable rate of return on their prudent investments. But upholding the regulatory compact should not mean that customers are precluded from investing in behind-the-meter solar. It is not in the public interest to establish an export credit rate that does not fully compensate DER, a rate so low that customers are not able to invest in solar to help manage their energy bills.

Instantaneous netting is not transparent to customers

Q. What issues do you anticipate with instantaneous netting?

A. I see two main issues with instantaneous netting. Firstly, when customers are considering an investment in solar power, they want to know how much they will save on their utility bill. That calculation requires the modeling of estimated solar production and the customer's consumption. Installers use tools like PVWatts to estimate monthly or hourly system production based on solar irradiance at the customer's home or business.[19] To my knowledge, there are no tools or data sources that provide estimates of real-time solar production based on the irradiance of specific locations. And on the consumption side of the equation, RMP does not provide

[18] See discussion on pages 3 and 4 of Hayes, Sara et al. (2011). *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency*. American Council for an Energy-Efficient Economy, Report Number U111. https://www.aceee.org/sites/default/files/publications/researchreports/U111.pdf

[19] PVWatts.https://pvwatts.nrel.gov/

customers access to real-time consumption data. Without reasonable estimates on production and consumption, bill savings estimates would be speculative at best and provide customers no reasonable way to calculate their return on investment. The second issue I see with instantaneous netting is that customers have no ability to increase or decrease their energy consumption in response to instantaneous changes in their solar system production. RMP does not provide customers with real-time information on energy use, and it is not reasonable to expect homeowners to turn off lights and appliances in response to real-time changes in solar production. Instead, I recommend hourly netting for the export credit rate to provide a reasonable buffer to allow customers to shift load in a timely manner.

Q. Are there technical solutions that could help customers manage load in real time?

A. Yes. RMP points out that there are "solutions that customers can deploy to respond to the price signals from an export credit rate will likely have the capabilities to shift load on a real-time basis with solar output. This includes such technologies as batteries, smart electric vehicle charging, and smart water heaters."[20] I agree that batteries can respond to real-time changes in price, however just because customers can install batteries does not mean they will. Batteries have been cost-effectively deployed in very few markets, mainly Hawaii and California due to high electricity rates and time-of-use ("TOU") rate schedules. Utah's electricity rates are low relative to states like Hawaii and California, and RMP does not provide a TOU rate for customers installing solar and battery storage. Based on a general understanding of the return on investment for solar investment, simply lowering the export credit rate is not enough to offset the increased cost of a battery system. RMP has provided no evidence that customers would actually invest in batteries in response to their proposal.

[20] Rebuttal Testimony of Robert M. Meredith, lines 165-169.

Furthermore, setting an export credit rate that only encourages self-consumption reduces the value that behind-the-meter resources can bring during peak times. Supposing a customer installed a battery and operated it to limit exports to the grid, then there is no ability for that battery to respond by exporting power during peak times or other critical periods. Designing an export credit rate that only encourages self-consumption runs counter to the idea of fully valuing DER.

Establishing a low export credit rate will eliminate the DER solar market in Utah

Q. Does the DPU believe that a low export credit rate will impact Utah's solar market?

A. DPU witness Mr. Davis seems skeptical that a low export credit rate will have any impact on the market. "The uptake of roof-top solar is attributable to customer's current economic sentiment, ability to purchase the system or make payments, adequate roof space facing in a desirable direction, a desire to offset energy use, or simply a desire to obtain energy from a renewable resource to name a few (buyer behavior)."[21]

Q. Do you agree with Mr. Davis's skepticism about buyer behavior in response to the export credit rate?

A. No. By not including energy bill savings in his list of buyer motivations, Mr. Davis ignores the fact that behind-the-meter solar is an investment, and that reducing the export credit rate will greatly increase the payback period for that investment. Based on surveys of our customers nationwide, potential savings (whether short-term or long-term) is the number one reason for installing solar. There are real examples of how significantly reducing compensation for distributed generation has resulted in catastrophic results for residential solar markets. In

[21] Rebuttal Testimony of Robert A. Davis, lines 364-367.

2015 when the Nevada Public Utilities Commission adopted an instantaneous netting compensation structure that would decline to an avoided costs rate, demand for residential solar plummeted by 92% and over 2,600 jobs were lost as companies withdrew from the market until the legislature reinstated net metering in 2017.[22]

The importance of potential savings is evident in how Utah's residential solar market has responded to the transition program. While the short-term value is similar to net metering, the long-term uncertainty due to the limited grandfathering period has led to lower levels of annual installations. RMP's proposed export rate would be the lowest in the United States, and thus it is not unreasonable to expect that it would significantly reduce customer demand.

Q. How would a reduction in the export credit to RMP's proposal affect customer investment in solar?

A. RMP's proposal greatly increases payback on the investment and will effectively shut down Utah's solar market. As part of the PacifiCorp 2019 Integrated Resource Plan, Navigant completed a forecast of private generation investment in each state PacifiCorp serves.[23] The forecast includes cost estimates, tax credits, and other policies. Navigant's base case forecast modeled an extension of Schedule 136 indefinitely out into the future. Based on that assumption, Navigant estimates that the market for residential PV will drop to 2.5 MW installed annually between 2022 and 2030.[24] A handful of small local installers may be able to serve a market that size, but national installers with lower costs based on economies of scale are unlikely to operate

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[22] Scientific American, Nevada Boosts Solar Power, Reversing Course (June 16, 2017) available at https://www.scientificamerican.com/article/nevada-boosts-solar-power-reversing-course/

[23] Navigant. Private Generation Long-Term Resource Assessment (2019-2038). https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-support-and-studies/PacifiCorp_IRP_DG_Resource_Assessment-2018_Final-Corrected.pdf

[24] *Ibid.*, Appendix D, page D-9

in the Utah market. Utah customers will be worse off because even if they are willing to accept longer payback times due to a low export credit rate, they will pay more for systems due to a lack of economies of scale, which will further increase payback times. To make matters worse, Navigant forecasts that scenario assuming a Schedule 136 export credit rate of 9.2 cents/kWh. If the export credit rate is set at 1.5 cents/kWh, no solar installers will be able to operate in the Utah market based on cost savings and investment payback. That's ignoring the other components of RMP's proposal (i.e., the $160 meter fee, the $150 application fee, and instantaneous netting), which would further erode customer savings and extend payback on the investment.

Gradualism and certainty are important to solar customers and solar installers

Q. How do you respond to proposals of gradualism raised by other parties?

A. I agree with USEA witness Mr. Evans that if the Commission approves an export credit rate lower than that of the Schedule 136 Transition Program, the megawatt caps of the Transition Program should be fulfilled before moving to the new export credit rate.[25] Parties to the stipulation settlement agreed that those capacity caps were reasonable. The Commission should enable developers and customers to satisfy the caps under the current Transition program terms.

I also agree with Utah Clean Energy witness Kate Bowman's proposal for an extended glide path that would use capacity thresholds to ratchet down the export credit rate value.[26] This sort of approach has been used in other states and may provide enough certainty to sustain the solar market in Utah.

[25] Rebuttal Testimony of Ryan Evans, lines 55-61.
[26] Rebuttal Testimony of Kate Bowman, lines 1078-1099.

Q. Do you still recommend customers receive a 20-year lock-in of their export credit rate when they interconnect?

A. Yes. Customer investment requires a level of certainty. If the terms of the export credit rate can change annually, the expected payback will be unclear and unstable, and it will limit customer investment. If the Commission declines to allow a 20-year lock-in of the export credit rate, the Commission should order a multi-year lock-in term that the Commission believes will afford customers a reasonable certainty on their investment.

IV. VISION FOR UTAH'S SOLAR MARKET

Q. What principles did you recommend the Commission use when adopting an export credit rate in this case?

A. In my direct testimony, I provided the following list of principles the Commission should consider when setting an export credit rate:[27]

- *Solar customers should receive fair compensation for the value provided to the grid.*
- *Solar policies should be certain and only change gradually.*
- *Solar policies should be understandable for customers.*
- *Solar policies should not treat retail customers like independent power producers.*

This list is grounded in traditional rate design principles and would not unfairly discriminate against customers that install on-site solar.

Q. Which costs should the Commission consider?

A. The Export Credit Rate should compensate customers for the full range of utility costs that are avoided or deferred. Some parties have outlined benefits of solar that have not

[27] Direct Testimony of Christopher Worley, lines 109-126.

traditionally been included in utility rates. Parties have provided quantitative estimates of those benefits, and some benefits have been discussed qualitatively. The Commission should consider all costs and benefits, quantitative and qualitative, including those that accrue to the utility and those that accrue to society. Utility ratemaking requires judgement. The Commission may decline to include some costs and benefits in their final determination, but all costs and benefits should be reviewed and considered.

Q. Are there future benefits the Commission should contemplate when adjudicating this case?

A. Based on estimates put forward by Vivint Solar and Vote Solar, exports from DERs provide grid benefits equal to or greater than the retail rate of electricity, and Utah's economy and environment benefit when customers invest in solar. These benefits accrue today. There is an opportunity for DER to provide even more benefit to RMP's grid, and by extension, the state of Utah. For example, adopting the IEEE 1547-2018 standard for interconnection of distributed energy resources would allow solar inverters to provide voltage and frequency support, providing more benefit to the grid.

Another example is battery storage, which can shift load away from peak times or provide grid support during critical periods. And while RMP seems to contemplate a future where customers install batteries along with their solar PV so that they reduce their solar exports[28], RMP's proposal may not result in batteries being installed. In my experience, battery storage is a cost-effective investment in very few states (like Hawaii and California). Given the terms of RMP's proposal, I find it unlikely that the thousands of dollars spent on a battery would improve the payback time for a solar plus storage system. A better approach to encourage

[28] Rebuttal Testimony of Robert M. Meredith, lines 78-85.

deployment of storage would be to offer a TOU rate schedule for customers with solar and storage. More utilities and utility regulators are considering TOU as a tool to better manage grids and to more efficiently allocate costs. With a high enough peak-to-off-peak ratio, customers can reduce the payback on their solar plus storage system by load shifting and discharging the battery during peak times.

The Commission has the opportunity in this case to chart a future where DERs are adequately compensated for the benefits they bring to the system. It is clear that RMP also understands the potential value that DERs can provide as evidenced by the innovative Soleil Lofts project. Solar paired with energy storage could participate in demand response or targeted dispatch programs to provide substantial benefits to all ratepayers. The recent windstorm that left tens-of-thousands of customers without power for a prolonged period of time shows the value of back-up power and how DERs can provide a more resilient grid. Undercutting solar compensation just as these opportunities are emerging would be extremely short-sighted. A future where behind-the-meter solar, inverters, and batteries enable a more efficient, resilient grid for the people of Utah. But DER investment in Utah will end if the export credit rate is set too low.

V. CONCLUSION

Q. To summarize, what are your recommendations for the Commission?

A. I recommend the following:

- Set the export credit rate at the retail rate based on the quantifiable, utility-specific components outlined in Table 1 and the qualitative value of economic, environmental, and societal values presented by parties in this case.

- The export credit rate should use hourly netting.
- Reassess the export credit rate every 3-5 years but allow customers to lock in a 20-year term for their export credit rate when they interconnect.
- The Commission should deny RMP's proposed $150 meter fee as discriminatory.
- The Commission should order RMP to provide new cost estimates for a tiered application fee.
- The Commission should contemplate incentive regulation to offset RMP's lost revenue and earning potential, perhaps opening a proceeding to investigate alternatives.

Q. Does this complete your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on September 15, 2020, a true and correct copy of Vivint Solar's surrebuttal testimony of Christopher Worley in Phase 2 of Docket No. 17-035-61 was served by email on the following Parties:

Division of Public Utilities

William Powell	wpowell@utah.gov
Justin Jetter	jjetter@agutah.gov
Patricia Schmid	pschmid@agutah.gov
DPU	dpudatarequest@utah.gov

Office of Consumer Services

Michele Beck	mbeck@utah.gov
Robert Moore	rmoore@agutah.gov

Rocky Mountain Power

Rocky Mountain Power Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com
	utahdockets@pacificorp.com
Emily Wegener	emily.wegener@pacificorp.com

Vote Solar

Rick Gilliam	rick@votesolar.org
Sachu Constantine	sachu@votesolar.org
Jennifer Selendy	jselendy@selendygay.com
Joshua S. Margolin	jmargolin@selendygay.com
Philippe Z. Selendy	philippe.selendy@selendygay.com

Utah Clean Energy

Sarah Wright	sarah@utahcleanenergy.org
Kate Bowman	kate@utahcleanenergy.org
Hunter Holman	hunter@utahcleanenergy.org

Utah Solar Energy Association

Ryan Evans	revans@utsolar.org

Salt Lake City Corporation

Christopher Thomas	christopher.thomas@slcgov.com

Auric Solar, LLC

Elias Bishop	elias.bishop@auricsolar.com

Western Resource Advocates

Sophie Hayes sophie.hayes@westernresources.org
Nancy Kelly nkelly@westernresources.org
Steven S. Michel smichel@westernresources.org

HealUtah

Noah Miterko noah@healutah.org

/s/ Stephen F. Mecham
Stephen F. Mecham