ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

July 15, 2020

VIA ELECTRONIC FILING

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

Attention: Gary Widerburg
Commission Administrator

RE: **Docket No. 17-035-61 – In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity**
Rebuttal Testimony

Pursuant to the Phase II Scheduling Order and Notice of Public Witness Hearing, and Notice of Hearing issued January 16, 2018 in the above referenced docket, Rocky Mountain Power (the "Company") hereby submits for filing its rebuttal testimony.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
Jana.saba@pacificorp.com
emily.wegener@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

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

Sincerely,

Joelle Steward
Vice President, Regulation

Rocky Mountain Power
Docket No. 17-035-61
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Joelle R. Steward

July 2020

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

A. Yes.

Purpose and Summary of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to various policy arguments raised by other parties in their direct testimony submitted on March 3, 2020,[1] related to the Company's proposed net billing program and export credit rate filed on February 3, 2020 ("Net Billing Program"). Specifically, I summarize and/or respond to testimony submitted by the Division of Public Utilities ("Division") witnesses Mr. Robert A. Davis and Dr. Abdinasir Abdulle; the Office of Consumer Services ("Office") witnesses Ms. Cheryl Murray; Utah Clean Energy ("UCE") witness Ms. Kate Bowman; Vivint Solar witness Mr. Christopher Worley; the Utah Solar Energy Association ("USEA") witness Mr. Ryan Evans; and Vote Solar witnesses Mr. Sachu Constantine, Dr. Albert J. Lee, Dr. Carolyn Berry, Mr. Curt Volkmann, Dr. Spencer Yang and Dr. Michael Milligan.

Q. Please summarize your rebuttal testimony.

A. The Company's proposed Net Billing program offers a sustainable program structure for customer generators that fairly balances the interests of customer generators and other non-participating customers. UCE, Vivint Solar, USEA and Vote Solar make various recommendations and proposals in attempt to continue a current or increased export credit rate that is unsustainable and shifts costs to other customers. The

[1] Vote Solar also submitted revised testimony on May 8, 2020.

Company's Net Billing Program offers a fair and balanced approach to support energy choices.

Q. Please summarize the parties' positions and the Company's response to the various proposals.

A. The Division expresses general support for the Company's proposed net billing program under a new Electric Service Schedule No. 137 ("Schedule 137") and export credit rate methodology. The Division affirms that the Company's proposal "seems to generally and properly align credit amounts with system value."[2] Mr. Davis also recommends a modification with regards to the seasonal definitions, which is addressed in the rebuttal testimony of Company witness Mr. Daniel J. MacNeil. The Office states two primary principles it believes should guide the outcome of this case: 1) the new program should be truly cost-based and eliminate subsidies to the greatest extent reasonable, and 2) the new program should be designed in a manner that is simple and easy for a customer to understand. The Office states that it generally supports the use of avoided costs, avoided line losses and integration costs in determining an export credit rate. It also offers some recommendations to the Company's Net Billing Program to clarify and simplify certain aspects of the program for customers. Company witness Mr. Robert M. Meredith addresses these proposals in his rebuttal testimony.

UCE, Vivint Solar, USEA and Vote Solar present specific proposals on the following issues:

<u>Export Netting</u>

UCE, Vivint Solar and Vote Solar advocate for a departure from the current 15-minute

[2] *See* Direct Testimony of Mr. Davis, line 407-408.

to a longer netting period. Mr. Meredith responds to the parties in his rebuttal testimony.

Gradualism

UCE, Vivint Solar and USEA argue that the principle of gradualism should be used in this proceeding. I address this issue later in my rebuttal testimony.

Term of Export Credit Rate

UCE, Vivint Solar and Vote Solar advocate for locking in the export credit rate for a term of 20 years. This proposal is discussed in the rebuttal testimony of Mr. MacNeil.

Export Credit Rate

Vivint Solar proposes a floor of at least 9.2 cents per kilowatt-hour ("kWh") be set for the export credit rate. Vote Solar proposes to set the rate at 22.22 cents/kWh. A detailed response to these proposals is presented by Company witnesses Messrs. MacNeil and Barker.

Integrated Distribution Planning

Vote Solar requests that the Commission initiate a formal integrated distribution planning process. Mr. Barker responds to this proposal.

Eliminate Expiration of Excess Generation Credits

Vote Solar requests that the Commission eliminate the expiration of excess generation credits. I address this proposal in my rebuttal testimony.

Reinstatement of Net Metering

As their primary proposal, Vote Solar asks the Commission to re-open net metering to new customers as of the effective date of the final order in this proceeding. I address Vote Solar's proposal in my rebuttal testimony.

Additionally, my testimony responds to various claims, statements and policy arguments the parties make to support their proposals.

Q. Please describe the parties' requests for the use of gradualism in this docket.

A. Ms. Bowman claims that a gradual transition to the new export credit rate is necessary to protect the rooftop solar market in Utah and minimize the economic impacts. Mr. Worley states that "solar policies should be certain and only change gradually."[3] Mr. Evans urges that gradualism is critical in helping small businesses adapt to changes in the circumstances of their business.

Q. Does the Company support the principle of gradualism as a sound ratemaking principle?

A. To an extent, yes, but not as an excuse for continual delay for needed change and providing for ongoing uncertainty. Gradualism is an important rate design principle and has been a guiding principle in this docket and its predecessor, Docket No. 14-035-114 ("NEM Docket"). Issues surrounding customer generation rates have been active in Utah since 2014. The Settlement Stipulation for the NEM Docket ("NEM Stipulation") was structured to employ gradualism to the transition to a sustainable rate structure for customer generators and developers. For customers who had already adopted customer generation, the NEM Stipulation grandfathered those customers on existing Electric Service Schedule No. 135 ("Schedule 135") until 2036. For customers seeking to adopt on-site generation over the next three years (subject to a cap), the NEM Stipulation grandfathered those customers on Electric Service Schedule No. 136 ("Schedule 136") with a fixed export credit rate through 2032. By the time the new

[3] *See* Direct Testimony of Mr. Worley, line 113.

export credit rates and Schedule 137 are implemented in this proceeding, the solar industry will have had almost seven years to adapt to the changes. Gradualism has already been employed. It is a disservice to all of the Company's customers to continue to pay above the fair value for exported energy.

Q. Mr. Evans, Ms. Bowman, Dr. Berry, and Mr. Worley express concern the Company's proposal will eliminate customer choice for solar in Utah. Do you agree?

A. No. Any customer who chooses to install solar panels on their roof has a right and opportunity to do so. Conversely, non-participating customers have the right to be protected from overpaying for the excess generation to subsidize the solar industry in Utah. Customers should be free to decide whether to install rooftop solar and should be fairly compensated for the true value of the electricity they provide.

Q. Several of the parties point to reduced growth in customer generation interconnections since the beginning of the Transition Program as evidence that it is detrimental to the solar industry. Do you agree with this characterization?

A. No. The Company experienced a sharp increase in interconnection applications in 2016 and 2017 likely due to the sunset provision of Schedule 135, which took effect on November 15, 2017. Interconnection applications in 2018 and 2019 exceeded applications in 2015 and earlier, which supports that the transition program did not adversely curtail the growth of customer generation. Additionally, a near-term moderation in the growth of new applications was expected as the incentive structure was adjusted.

Q. Is it appropriate to subsidize the rooftop solar industry in Utah through artificially high export credit rates in order to provide economic benefits, such as jobs?

A. No. The role of the Commission as an economic regulator is to establish just and reasonable rates, not to increase job growth in a single industry. Customers who make the decision to purchase a solar system for their home or business should not be subsidized with above-value compensation for their excess energy. Parties' claim that the Company's proposal could affect the growth of the solar industry and related jobs in Utah fails to acknowledge the greater positive impact on the economy from maintaining the Company's ability to provide low-cost electricity to all of its customers. It also puts an unfair burden on Rocky Mountain Power's customers to support a state-wide industry. Commission-enabled subsidies would be contrary to state policy that recognizes a phase-out of tax credits that support the industry.

Q. Do you agree that subsidizing customer generation introduces competitive forces into the market that open a pathway to benefits?

A. No. Subsidies, by their very nature, reduce competitive forces rather than introducing them. If 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. The solar industry has already had the benefit of subsidies for many years, which have likely supported the decline in costs which enable solar to now be a more competitive resource. True competitive benefits occur when an industry can operate without subsidies.

Q. Dr. Berry claims that the Company is interested in eliminating customer generation because it threatens the profits of the utility. How do you respond?

A. This argument demonstrates a lack of understanding of how cost recovery for the utility works. While the Company may have to absorb a loss of revenue and fixed cost recovery in between rate setting, the Company always has the opportunity to address any revenue reduction by filing a general rate case. If a customer class does not pay the full costs that the Company incurs to serve them, those costs are then ostensibly shifted to other customers. Accordingly, this is not primarily an issue of the Company's bottom line; this is an issue of fairness among our customers.

Q. Dr. Berry also states that the Company is threatened by customer generation because over the long term it threatens rate base growth, which is how the Company earns a return. Do you agree?

A. No. Dr. Berry's claim that the Company does not have to plan for and build resources to serve customers with onsite generation is misguided. The Company must be ready to meet the full requirements of its customers, including those with onsite generation. The Company does this in the least-cost, least-risk manner through integrated resource planning and competitive solicitations that can result in either Company-owned resources, which are part of rate base, or with power purchase agreements, which are not part of rate base. Therefore it is incorrect to just assume that the growth in customer generation is merely a threat to the Company's growth in rate base; in reality, it undermines lower-cost generation alternatives for customers generally unless the rates for customer generation better reflect those alternatives.

Q. Mr. Constantine claims that the current practice of eliminating excess generation credits on an annual basis "can create perverse price signals that incentivize customers to waste energy on uneconomic end uses to avoided large balances of energy being forfeited to the utility."[4] Should the Commission approve this proposal and require the Company to monetize the excess generation credits and pay customers for output in excess of their annual usage?

A. No. This requirement would create a perverse incentive for customers to oversize their system. This would not be consistent with the underlying policy that enabled customer generation programs to begin with, which is to allow customers to offset their own usage, not become mini-wholesale power producers. If the Commission were to end the expiration of export credits, it should take other measures to prevent customers from installing over-sized systems, such as establishing a customer generation facility cap for interconnection up to the size of the customer's annual usage in order to ensure the right sizing of facilities.

Q. Mr. Constantine attempts to address the concern of over sizing by pointing to the approach used by Arizona Public Service that caps systems at 25 kW. Would implementing this in Utah alleviate your concern?

A. No. Capping residential system size at 25 kW alone, which is already a provision in all of the customer generation tariffs and the proposed Schedule 137, does not adequately address over-sizing. The average system size for a residential customer with onsite generation is 6.6 kW. The average maximum load for an average residential customer taking service from the Company is 7.6 kW. The 25 kW residential system cap is nearly

[4] *See* Direct Testimony of Mr. Constantine line 508-510.

three times the average facility size to support an average residential customer's on-site usage and does not by itself prevent prospective customer generators from oversizing their system. Letting excess credits expire annually prevents customers from in essence becoming wholesale energy providers. Customers have the ability to become a small qualifying facility under PURPA and receive avoided costs for their facility output under the Company's Electric Service Schedule No. 37 if they want to be power producers. The current practice of the credits expiring in March of each year is appropriate to ensure customers right-size their facilities to match their annual usage without the more administratively complex and inflexible approach of capping facility size at interconnection to account for changes in usage over the course of a year.

Q. Vote Solar's primary proposal is to re-open the net metering program to new customers. Do you agree?

A. No. The NEM Stipulation that ended the Company's net metering program was the result of extensive negotiations over approximately nine months, supported by the governor's office, and signed by 14 parties that included regulatory staff, consumer advocates, environmental advocates, solar industry companies and various customer groups. The Commission approved the NEM Stipulation on September 29, 2017. Utah Code Ann. section 54-7-1(1) encourages informal resolution of matters brought before the Commission to minimize time and expense expended by utilities, the state, and consumers, to enhance administrative efficiency, and to allow the Commission to concentrate on disputed matters. Undoing a settlement three years after the ink is dry would set a precedent that would permanently undermine future settlement efforts and importantly, undo the considerable amount of effort and compromise undertaken by the parties to reach the NEM Stipulation. This proposal has no merit and should be dismissed by the Commission.

Conclusion

Q. Please summarize your recommendation?

A. The Company recommends the Commission approve its proposed Net Billing Program that provides customers the opportunity to invest in onsite generation while insulating other customers from the effects of that decision. The proposals set forth by UCE, Vivint Solar, USEA, and Vote Solar should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 17-035-61
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Daniel J. MacNeil

July 2020

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

A. Yes.

Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. I respond to the direct testimony of Vote Solar witnesses Dr. Michael Milligan, Mr. Curt Volkmann, Dr. Spencer Yang, and Mr. Sachu Constantine; Vivint Solar witness Christopher Worley, and Utah Clean Energy ("UCE") witness Ms. Kate Bowman. My testimony supports the Company's proposed export credit rates for Schedule 137 - Net Billing Service.

Q. Please provide a summary of your rebuttal testimony.

A. The witnesses for Vote Solar and Vivint Solar propose export credit rates well in excess of the Company's proposal. For a variety of reasons, the rates proposed by these parties are not consistent with the costs non-participating customers would otherwise incur in the absence of exports under the proposed Schedule 137. My rebuttal testimony addresses each of the components proposed for inclusion in the export credit rate by the parties.

Vote Solar, Vivint Solar, and UCE also propose that customers be allowed to lock in export credit rates for a 20-year term. This proposal is inconsistent with cost-of-service ratemaking, where rates are subject to change to ensure they continue to align with costs. Because deliveries under Schedule 137 are always at the customer's option, this proposal is also inconsistent with the Company's long term contract terms as there is no reciprocal obligation on customers commensurate with the proposed fixed price term.

UCE suggests that export credit rates contemplated in this proceeding are essential for growing distributed energy resources as a whole, while Vote Solar suggests that export credit rates are a "lever" for achieving the Commission's energy policy goals.[1] Customer generation is one of many distributed energy resource options available, and a relatively minor one since other options like Cool Keeper or irrigation load control provide control and flexibility and thus significantly higher value.

Q. What are your recommendations?

A. The Company recommends that the Commission approve the Schedule 137 export credit rates and structure as filed by the Company and require annual updates to ensure avoided costs continue to align with the compensation provided for customer generation ("CG") exports.

Avoided Energy Costs

Q. What are parties' proposals for avoided energy costs?

A. Both Vivint Solar and Vote Solar propose that avoided energy costs reflect market prices. Mr. Worley, for Vivint Solar, proposes that avoided energy be valued using historical Energy Imbalance Market data.[2] Dr. Milligan, for Vote Solar, proposes that avoided energy be valued using a 20 year forecast of hourly market prices at Four Corners, Mead, and Mona based on PacifiCorp's official forward price curve.

[1] *See* lines 897 through 901 of Vote Solar witness Dr. Carolyn Berry's Revised Affirmative Testimony.
[2] *See* lines 155 through 160 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony.

Vivint Solar's Avoided Energy Proposal

Q. How does Mr. Worley propose to identify the value of customer generation exports?

A. Mr. Worley indicates that 90 percent of solar production occurs between the hours 9:00 am and 7:00 pm, and proposes prices based on a simple average of prices between those hours in all months.[3]

Q. Do you have concerns with Mr. Worley's proposal?

A. Yes. As shown in Mr. Worley's Table 2, prices vary significantly across the selected solar production window. The expected export profile also varies significantly. For example, exports are likely to be below average or zero in hour 19 in October, which has the highest price shown in Table 2. Exports are likely to be above average in hour 13 in April, which has the lowest price shown in Table 2. Because Mr. Worley has given an equal weight to all intervals, his calculation significantly overestimates the average market price during periods of exports.

Q. What specific market price information does Mr. Worley propose to use?

A. Mr. Worley has used data that excludes "adders" associated with greenhouse gas value, transmission congestion, and line losses.[4]

Q. Is it appropriate to exclude CAISO's greenhouse gas and transmission congestion adders?

A. No. The reported energy value on its own is a "System Marginal Energy Cost" that is

[3] *See* lines 155 through 160 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony. Note that it is not clear whether Mr. Worley has accounted for the fact that CAISO reports values in Pacific Prevailing Time.
[4] *See* lines 165 through 169 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony.

the same throughout the EIM footprint.[5] By removing these adders, Mr. Worley is removing the very location-specific elements he is intending to incorporate by selecting a price point in Utah. He is also incorporating greenhouse gas costs that are only applicable to resources serving load within California and which are not applied to incremental load or resources elsewhere. Because transmission congestion and greenhouse gas costs typically contribute to higher prices in California, the adders applicable to location in Utah are generally negative. Removing them thus overstates the value of energy in Utah.

Q. Does Mr. Worley's proposal effectively account for line losses as he suggests?

A. No. The marginal line loss adjustment included in the CAISO EIM data reflects an estimate only of the contribution of losses to the difference in locational marginal prices between two points on the transmission system. The Company's proposal included an adjustment to account for avoided transmission and primary distribution losses as a result of customer exports onto the secondary distribution system. The losses included in the Company's proposal are not captured in either the base price used by Mr. Worley or the reported line loss adder and would thus be incremental.

Q. Do any of the elements of Mr. Worley's proposal have merits?

A. Yes. The use of historical data can provide a data point that avoids much of the complexity inherent in forecasting or production cost modeling. However, to provide a meaningful estimate, the historical price and volume data should be from the same time period. The Company's load research study provides historical export volume data for

---

[5] Please refer to the California Independent System Operator's Tariff, Appendix C: Locational Marginal Price. Available at: http://caiso.com/Documents/AppendixC-LocationalMarginalPrice-asof-Aug1-2019.pdf (accessed on 5/14/2020).

the 12 months ending September 2019. My direct testimony described the development of on-peak and off-peak pricing periods using fifteen-minute EIM data that spans this period and includes the appropriate adjustments reported for losses, congestion, and greenhouse gas costs.[6] Historical avoided energy value can be measured by multiplying the total export volumes by the EIM price.

Q. What is the value of historical exports using EIM prices from the same periods?

A. In the 12 months ending September 2019, the average Schedule 136 export profile from the Company's census had a value of $20.50/megawatt-hour ("MWh"), based on 15-minute interval CG export volumes and 15-minute EIM prices.

Q. Was there a relationship between the historical prices and export volumes?

A. Yes. Historical exports tended to be lower when market prices were above average. If export volumes had been uniform in each hour of a given month, for example the same level of exports from 6:00 p.m. to 7:00 p.m. every day in July, the historical value would have been $21.73/MWh, or about 6 percent higher.

Q. Are there reasons to expect fewer exports when market prices or marginal costs are high?

A. Yes. When a customer's load is high, more customer generation can be utilized onsite leaving less to be exported to the grid. To the extent increased customer load is due to weather conditions that span a significant area, such as high temperature periods in the summer time, overall system load is likely to be higher, which tends to result in higher marginal costs. While clear days in the summer may result in increases to both customer

[6] *See* lines 86 through 89.

generation and load, the historical data indicates that exports are more likely to occur during lower value conditions.

Q. Are any adjustments to the historical value appropriate for determining an export credit rate for residential and small non-residential customers?

A. Yes. EIM prices do not reflect the value of avoided primary and transmission losses. They also do not reflect the integration cost associated with keeping resources available that can match the moment to moment variations in customer exports. Accounting for these elements consistent with my direct testimony, but incorporating the updated EIM energy price values, results in an average incremental value of $1.75/MWh for avoided losses and a cost of $0.15/MWh for integration. Details on these results are presented in Exhibit RMP___(DJM-1R).

Q. How does an export credit rate based on historical energy values compare to the Company's proposal based on a forecast for 2021?

A. The historical value results in an average export credit of $22.09/MWh, which is $6.83/MWh higher than the Company's forecast. This difference is likely attributable to the fact that the GRID model includes an additional 459 megawatts ("MW") of contracted solar resources in Utah with commercial operation dates prior to 2021 that were not online in the historical period. Because this additional solar has zero marginal cost, it will reduce the need for the highest cost resources in each hour which previously set EIM prices, and will result in a tendency toward lower EIM prices in the future, at least during periods when it has significant output. Periods of significant utility-scale solar output are likely to coincide with the periods when customer generation exports are highest.

Q. What do you conclude with regard to Vivint Solar's avoided energy proposal?

A. Vivint Solar simplifies the complexity of the avoided energy cost calculation. Using historical EIM pricing weighted by the historical delivered volumes in each interval, as opposed to a simple average over daylight hours as proposed by Vivint Solar, would produce a very accurate historical avoided energy value without requiring complicated models. It could be reasonable to use those historical values to set a prospective export credit rate, but it would be important to frequently update that rate to ensure it continues to reflect recent conditions. While the Company believes its modeling reasonably accounts for the avoided energy value of customer generation exports under expected future conditions, the ease of calculating and reviewing a value derived from historical EIM data are points in its favor. The Company is open to this concept so long as the historical prices and volumes are aligned and the value is updated frequently.

Vote Solar's Load Research Study

Q. Would the historical value estimate based on EIM change significantly based on the regression-based export profile from the load research study ("LRS") produced by Vote Solar witness Dr. Lee?

A. No. Dr. Lee's export profile reflects data for calendar year 2019, while the Company's data is for the 12 months ending September 2019, so only 75 percent of the data is directly comparable. Over the overlapping period, Vote Solar's export profile has a value that is 1.6 percent higher than that of the Company's export profile. Over the entire 12 months, Vote Solar's export profile has a value that is 2.1 percent lower than that of the Company's export profile. This is likely primarily a result of market prices, which were an average of 18 percent lower in October–December 2019 than in the same months in 2018.

Q. What are the main differences between Vote Solar's export profile and the Company's?

A. Vote Solar's export profile has slightly more relative output in July and slightly less in March. Because the highest market prices tend to occur in the summer, this is likely driving the slight increase in market value.

Q. What population is used to forecast Vote Solar's LRS?

A. Vote Solar used a sample of Schedule 135 customer data plus all Schedule 136 customer data to estimate the total exports for both schedules.

Q. What population is included in the Company's LRS?

A. The Company's LRS included data from all Schedule 136 customers and calculates the average exports per customer.

Q. What is the primary population of interest in Phase II of this proceeding?

A. Schedule 137 customers, i.e. those applying to interconnect after Schedule 136 has been closed to new service, which is expected to occur near the end of this year.

Q. Are there reasons to believe Schedule 137 customers will have exports that are more similar to Schedule 136 customers than Schedule 135 customers?

A. Yes. Schedule 136 customers have more recent systems, since they have all interconnected in the past few years since Schedule 135 was closed to new service. At the same time, solar costs have been declining and efficiency has been improving.[7] In

[7] *See* Slide 14 in National Renewable Energy Laboratory presentation: U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018, October 2018. Available online at: https://www.nrel.gov/docs/fy19osti/72133.pdf (Accessed on 5/15/2020).

addition, solar systems tend to experience degradation that reduces their output over time, further differentiating between new equipment and old equipment. As a result, the systems installed by Schedule 137 customers are likely to be more similar to the recent interconnections associated with Schedule 136 customers than the older technology associated with Schedule 135 customers. Schedule 136 customers are also likely more reflective of future Schedule 137 customers than Schedule 135 customers, because the compensation structure for Schedule 136 has export credits that are priced lower than retail energy charges. In contrast to traditional net metering, Schedule 136 customers have an incentive, although fairly small, to use more of their generated energy onsite by either shifting load to high production times or sizing their system smaller relative to their own load requirements.

Q. What do you conclude with regard to the export profile proposed by Vote Solar?

A. Vote Solar's regression analysis is the culmination of a significant expenditure of effort that does not result in a significant change in estimated exports relative to the Company's census of Schedule 136 customers. In addition, by incorporating the effects of Schedule 135 customers, the changes may not be reflective of the Schedule 137 customers that will actually be subject to the export credit rate. As a result the Company recommends continuing to use the Company's census of Schedule 136 customer exports to calculate the export credit rate in this proceeding. Furthermore, it will be appropriate to incorporate the latest available information on exports in the Company's proposed annual updates, and the census of actual Schedule 136 exports will continue be available without significant further analysis, unlike the proposed regression.

Vote Solar's Avoided Energy Proposal

Q. What is Vote Solar's avoided energy cost proposal?

A. Dr. Milligan, for Vote Solar, proposes that avoided energy be valued using a 20-year forecast of hourly market prices at Four Corners, Mead, and Mona based on PacifiCorp's official forward price curve ("OFPC").

Q. How do Dr. Milligan's proposed avoided energy values for 2021 compare to the other proposed avoided energy costs?

A. Dr. Milligan's average energy price for 2021 is $24.44/MWh, which is $4.38/MWh higher than the average historical EIM value of the exports from the Vote Solar LRS. The price is also $9.99/MWh higher than the Company's GRID model results for 2021.

Q. Are there fundamental differences in the Company's OFPC and actual EIM prices?

A. Yes. The Company's OFPC represents <u>forward</u> prices, which are prices for committing today to deliver volumes in a future period, while EIM represents the cost of the marginal resource a few minutes into the future. In the first three years, the OFPC reflects the current offers available in the market for heavy load hour and light load hour products. Thereafter, the Company's OFPC transitions to a fundamentals forecast, based on production cost modeling of the western interconnect that estimates marginal resource dispatch costs, but it retains a forward premium consistent with current market offers.

Q. What is the forward premium?

A. The forward premium represents the risk of market price movements between the time of the contract and delivery, and declines as delivery approaches because conditions during the delivery period become more certain. Generally, prices are susceptible to large upward spikes and modest downward movement. This is due to the characteristics of the resource supply stack and the need to match load and resources in real-time operations. When there are only a few high cost resources that can be deployed, load-serving entities will pay essentially any price to meet their customer loads, driving prices up significantly for the last few megawatts of supply. When there are extra resources available, changes in supply tend to impact prices by a small amount, because the next resource either up or down from the marginal resource is likely to have relatively similar costs. This is particularly true with the current low gas prices, because the impact of differences in heat rates shrinks and the cost of coal and gas resources can overlap. Plus, as prices approach zero, particularly for extended periods, there are a range of resource options that reduce the risk of negative pricing, including gas and coal shutdowns, hydro spill, and renewable curtailment. This places a lower bound on the risk of prices falling. As result of the risk of higher prices, sellers will require more compensation than their expected marginal costs, hence the forward premium.

Q. Are forward markets as granular as EIM?

A. No. Forward markets primarily trade in monthly or quarterly heavy load hour or light load hour blocks, in 25 MW increments, while EIM transactions are for five or 15 minute intervals in less than 1 MW increments. As a result, even if the Company wanted to sell an export profile on a forward basis, it could not do so solely with forward market transactions, and would need to shape around a block product with generation resources or hourly market transactions entered shortly before delivery. Further, while forecasted amounts could conceivably be sold on a forward basis, all uncertainty between forecast and actual exports and all sub-hourly volume changes would be settled in EIM based on the dispatch costs of either PacifiCorp's resources or those of other market participants, and could not be settled on a forward basis.

Q. Are forward markets as liquid as EIM?

A. No. In EIM, there are no variable wheeling charges so the next marginal unit can be located several balancing authority areas away without incurring extra transmission costs. Because of transmission costs, forward market transactions generally occur at tie points between two or more transmission systems. Any resource that is not located on the connected transmission systems will need to have transmission to wheel across any intervening systems and may incur line losses. Even resources that are on a connected transmission system may need to pay for transmission. While resources designated to serve retail customers are not charged for transmission service (as charges are billed to network load), a network resource must be "undesignated" and separate transmission service acquired before its output can be sold to anyone other than retail customers, except for EIM transactions.

Generally, the Company considers the Mid-Columbia and Palo Verde markets to be liquid, as there are enough entities connected to these markets or holding long term transmission reservations (such that they have zero marginal transmission costs), to provide competitive pricing and significant market depth under most conditions.

In the Company's experience the Mead, Mona, and Four Corners markets are less liquid. At such points, only those counterparties that could transact without incurring the cost of one or more additional transmission reservations are able to provide highly-competitive market offers. As such, the volume available and the offer price in those locations are more sensitive to market conditions than the Mid-Columbia or Palo Verde markets.

Q. Does the GRID model allow for unlimited market sales at the Mead, Mona, and Four Corners markets?

A. No. Market sales are limited by transmission capacity, based on PacifiCorp Energy Supply Management's transmission reservations, and by capacity limits, based on historical sales volume. These limits help ensure that valuations primarily reflect the expected benefits of serving retail customers, rather than speculative wholesale sales revenues.

Q. Dr. Milligan states that due to operational or system constraints, "market prices provide a conservative estimate of the value of CG exports."[8] Do you agree?

A. No. Operational and system constraints that prevent an otherwise willing buyer and seller from transacting necessarily result in the buyer seeking higher-priced alternatives and the seller seeking lower-priced alternatives. As a result, to the extent the Company expects to be a net seller in a given hour at a given market price, a conservative estimate of the value of CG exports would be lower than market. To be accurate, an estimate of the value of CG exports must account for both the frequency of periods in which lower-revenue alternatives are called upon, and the revenues or cost savings in those hours.

Q. What do you conclude with regard to Vote Solar's avoided energy proposal?

A. Vote Solar's avoided energy proposal overstates the value of CG exports because forward market prices reflect a premium for price and volume certainty that is inconsistent with the volumes that might or might not be exported by customer

[8] *See* lines 225 through 228 of Vote Solar witness Dr. Milligan's Revised Testimony.

generators in any future period. In addition, because of limits on transmission and market depth, the Company does not assume that all incremental volumes can be sold at market prices in either its Integrated Resource Plan ("IRP") or in the GRID model, which supports the Company's proposed calculation of the avoided energy costs in this proceeding. Vote Solar's proposal disregards these factors and should be rejected.

Avoided Generation Capacity – Capacity Contribution

Q. Do parties propose that CG exports be credited for avoiding generation capacity?

A. Yes. Both Vivint Solar and Vote Solar propose that CG exports should be compensated for avoiding generation capacity. Avoided generation capacity consists of two components: a volume and a cost. The volume of generation capacity avoided by a resource is often characterized as its capacity contribution. This section discusses the capacity contribution proposed by parties' for CG exports.

Q. What are the capacity contribution values for CG exports proposed by parties?

A. Vivint Solar proposes using a solar capacity contribution of 42 percent and identifies PacifiCorp's 2019 IRP as the source.[9] Vote Solar proposes a capacity contribution of 27.65 percent.[10]

Q. How was Vivint Solar's proposal derived?

A. It is not clear. PacifiCorp's 2019 IRP includes a Capacity Contribution Study as part of Appendix N. The only seemingly applicable instance of a 42 percent contribution for a Utah solar resource was in Table N.3, which reports initial estimates of the capacity contribution of renewable resources combined with battery storage. Besides including benefits attributable to the entire output from a tracking solar resource that is combined

[9] *See* lines 190-192 of Vivint Solar witness Mr. Worley's Direct Testimony.
[10] *See* lines 528-531 of Vote Solar witness Dr. Milligan's Revised Testimony.

with battery storage, which is not comparable to CG exports, Appendix N goes on to describe how these estimates are highly dependent on portfolio selection. With that in mind, values were calculated at the conclusion of the 2019 IRP based on a portfolio that was closely aligned with the preferred portfolio and reported in Appendix N.[11] The final capacity contribution values reported in the 2019 IRP for tracking solar resources in Utah equate to approximately 11 percent on an annual basis.[12]

Q. Is the 11 percent capacity contribution described above appropriate for a rooftop solar resource?

A. No. By orienting its panels toward the sun throughout the day, a tracking solar resource has more generation during the early morning and late afternoon when the sun isn't high in the sky, relative to rooftop panels with a fixed orientation. Because of the prevalence of solar resources already on PacifiCorp's system, and the solar resources anticipated to be economic elements of the preferred portfolio in the next few years, generation supply is plentiful and the risk of loss of load events is low while the sun is high in the sky. As a result, even with expanded generation as a result of tracking equipment, the capacity contribution of tracking solar is relatively low. Rooftop solar, without tracking equipment, would have an even lower contribution.

Q. Is the generation profile of rooftop solar the appropriate basis for determining the capacity contribution of CG exports?

A. No. Because rooftop solar generation is first allocated to serving a customer's own load, the exported volumes are only a portion of the total output. When the sun is not

[11] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02. Volume II. Appendix N. Figures N.4 and N.5.
[12] To provide an annual value, the reported summer and winter values are weighted based on the number of loss of load hours in the study that occurred in the respective periods: 92 percent summer and 8 percent winter.

high in the sky and rooftop solar generation is relatively low, a customer's own load is more likely to consume all or most of the generation onsite, leaving little to be exported. Moreover, this effect will be exacerbated whenever a customer's own load is highest, such as on the hottest days of the year that drive peak generation requirements.

Q. How was Vote Solar's proposal derived?

A. Dr. Milligan presents an extensive overview of the theory of capacity contribution calculations, but ultimately makes a relatively simple calculation. Dr. Milligan compares Vote Solar's CG export profile, provided by Dr. Albert Lee, to the Company's forecasted Utah load used in its 2017 IRP, and calculates the simple average of CG exports during the top 10 percent of load hours in each year from 2021 through 2037.

Q. Is Dr. Milligan's capacity contribution calculation reasonable?

A. No. Dr. Milligan's calculation has numerous flaws which result in an over-estimation of the capacity contribution of CG exports. First, Dr. Milligan disregards the relationship between weather, load, and CG exports. Second, Dr. Milligan's calculation uses Utah load rather than the system load upon which the Company's long term planning and resource procurement is based. Finally, and most importantly, Dr. Milligan disregards the impact of the Company's current resource portfolio and its optimized expansion plan on the risk of loss of load events.

Q. What is the first flaw in Dr. Milligan's calculation?

A. Dr. Milligan has compared Vote Solar's LRS, based on weather conditions in 2019, against PacifiCorp's load forecast for 2021 through 2037, which reflects normalized weather conditions. Comparing exports and a load forecast from different years would only be a valid assumption if there was no relationship between weather, load, and CG exports, i.e. if load and CG exports vary randomly relative to each other. The highest loads in PacifiCorp's normalized load forecast occur on a weekday in the third week of July. The exact weekday varies from year to year, rotating with the calendar in the same way that the fourth of July can occur on any day of the week. Dr. Milligan made no attempt to account for the difference between the historical export profile and variations resulting from either the day of the week or weather conditions.

Q. Is there reason to believe that CG exports are impacted by day of the week and weather conditions?

A. Yes. Vote Solar witness Dr. Lee indicates that both weather and day of the week are a factor in exports.[13] As a result, Dr. Milligan's calculation is disregarding relationships that were significant enough to be called out by his own colleague.

Q. Is there a readily available way to control for day of the week and weather conditions?

A. Yes. The most straight-forward way to align day of the week and weather conditions in a comparison of CG exports and retail load is to use data from the same period. Since the CG export profile is based on 2019, it would be appropriate to compare it to actual retail load from that year. Using actual Utah hourly loads from 2019, the average CG exports during the top ten percent of load hours is 22 percent, which is appreciably less than Dr. Milligan's calculation of over 27 percent. This indicates that Dr. Milligan's proposal is missing the real-world relationship between CG exports and peak load conditions, and is producing an overstated capacity contribution.

[13] *See* lines 118-128 of Vote Solar witness Dr. Lee's Revised Testimony.

Q. Is there a way to discern whether day of the week or weather is the driving factor in the difference between Dr. Milligan's calculation and the calculation based on the same historical conditions?

A. Yes. To the extent day of the week was the primary factor, Dr. Milligan's annual calculation should approach that based on the historical results every few years when the weekdays and weekends in 2019 line up with the weekdays and weekends in the forecast period. For example, July 1, 2019 was a Monday. July 1st will also be a Monday in 2024 and 2030.

Q. Does the data indicate that weekdays and weekends are an important factor?

A. No. Dr. Milligan's average capacity contribution in 2024 and 2030 was 28.12 percent, which is higher than his overall average of 27.65 percent. This is moving in the opposite direction of the actual results from 2019, indicating that day of the week is not the cause of the discrepancy between Dr. Milligan's forecast and the historical actual results. This leaves weather as the likely driving factor in those results.

Q. Why is weather an important factor with CG exports?

A. Weather, and in particular temperature, is the most important driver of customer load. Utah loads are summer peaking, with the highest loads on the hottest days, and temperature-driven loads generally impact customers over a wide area. When temperature drives up a customer generator's load, their ability to use their generation onsite increases, leaving less surplus available to export during the periods when the region or the system as a whole is experiencing the highest loads. In addition, all else being equal, the output of photovoltaic systems generally decreases as temperature rises, which would also contribute to reduced exports on the hottest days.

Q. Could differences between Schedules 135 and 136 and the proposed Schedule 137 further impact the capacity contribution of CG exports?

A. Yes. Schedule 135 customers have no incentive to shift usage into periods when their own generation resources are producing, and Schedule 136 customers have a limited incentive, since the difference between their compensation and their avoided retail rates is small. As a result, both Vote Solar's LRS and the Company's LRS would not be expected to have significant load shifting to align with generation production. In contrast, under the Company's proposed rates for Schedule 137, customers would have a strong incentive to use as much of their own generation as possible, as the avoided retail rate is significantly higher than the Company's proposed export credit. As a result, Schedule 137 customers would benefit from programming air conditioners, electric water heaters, and other appliances to run while their own solar is available, thereby reducing the proportion of their solar output that is exported. Because air conditioning is temperature-dependent, exports would likely drop the most during the hottest conditions, further diminishing the value of what is exported to meet peak requirements.

Q. What do you conclude with regard to CG exports and peak-producing weather?

A. Dr. Milligan's proposed capacity contribution calculation for CG exports is overstated because it disregards interactions between CG exports and peak-producing weather conditions. In reality, CG exports tend to be lower than average under peak load conditions, resulting in a lower capacity contribution.

Q. What is the second issue with Dr. Milligan's proposal?

A. Dr. Milligan's proposal is based on the Company's highest Utah loads, but the

Company's planning is based on meeting customer demand across its six-state footprint.

Q. Why does the Company's resource planning encompass its entire footprint?

A. Sharing resources and requirements across a wide geographic area captures diversity such that a reduced quantity of resources is necessary to achieve a given level of reliability. Sharing resources also provides economies of scale and spreads the risk of resource outages or generation shortfalls across a larger pool.

Q. How do 2019 CG exports compare to system-wide loads?

A. Replicating Dr. Milligan's proposed capacity contribution calculation, the simple average of CG exports during the top 10 percent of system-wide load hours in 2019 is 19 percent. The reduction relative to the 22 percent value using Utah load data reflects the fact that the Company's loads in California, Oregon, and Washington generally experience their annual peak loads in the winter. The highest winter loads generally occur in either the morning or the evening, which are periods when solar output and CG exports are relatively low. In 2019, every single Utah load hour within the top 10 percent occurred between June and September, while 17 percent of the system loads within the top 10 percent occurred outside of those months.

Q. Does switching Dr. Milligan's calculation to use historical, system-wide loads result in an accurate estimate of the capacity contribution of CG exports?

A. No.

Q. Why not?

A. The premise of Dr. Milligan's calculation is that the highest load hours are the periods in which the Company faces the highest risk of loss of load conditions. However, this load-based method does not take into account how the risk of loss of load is affected by resource mix and portfolio composition.

Q. How does resource mix affect the calculation of capacity contribution?

A. The premise of the capacity contribution calculation is to distill a resource's system impacts into a single value of pure "capacity". Those capacity values are intended to be interchangeable building blocks for meeting planning reserve requirements and reliably serving load, but the interchangeability necessarily breaks down when significant quantities of resources that are strongly correlated are added. Consider a system with one loss of load event during the day, and one loss of load event during the night. The addition of a solar resource could eliminate the loss of load event during the day, and in that simple example, the solar resource might be assigned a 50 percent capacity contribution. Adding a second solar resource would do little during the day, as no loss of load events remain, and nothing at night, so the second resource might be assigned a zero percent capacity contribution.

Q. Did the Company identify resource mix as a driver of capacity contribution in its 2019 IRP?

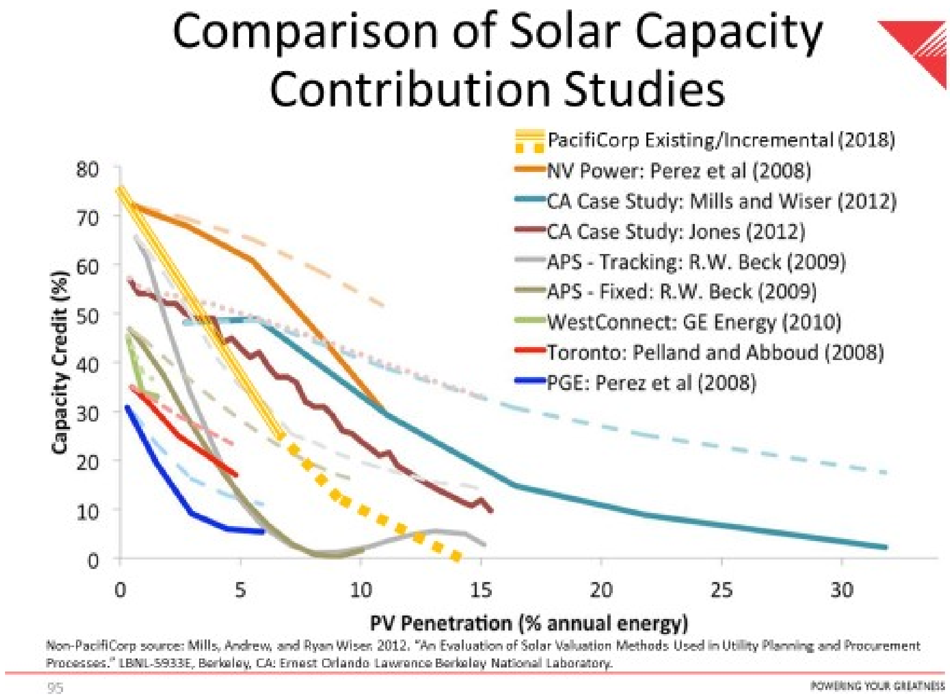
A. Yes. At the start of the 2019 IRP, the Company prepared capacity contribution values for solar resources at various levels of penetration. As more solar resources are added, more megawatts of resources are available when the sun is shining and the risk of loss of load during those hours declines. As a result, the capacity contribution of each additional solar resource also declines. The results of this analysis are shown in Table N.1 of the 2019 IRP, which identifies a capacity contribution of 43 percent for the roughly 2,200 MW of solar resources in the Company's initial portfolio (representing existing contracts and commitments), declining to 15 percent for the first 1,000 MW of solar resource additions and two percent for the next 1,000 MW of solar resource additions. The value of 43 percent for 2,200 MW represents the average value across the entire set of resources - the value declines continuously as solar resources are added, such that the first MW of solar resources has a much higher value than the 2,200th MW.

Q. Have studies by other utilities identified declines in capacity contribution as solar resource penetration increases?

A. Yes. Figure 1 shows the relationship between capacity contribution and solar penetration level in a variety of studies, including the Company's analysis for the 2019 IRP. This figure was presented at PacifiCorp's September 27-28, 2018 IRP public input meeting. [14]

[14] *See* Slide 95. Available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2018-09-27-28%20-%20General%20Public%20Meeting.pdf (accessed 6/15/2020).

Figure 1



Q. Where does Dr. Milligan's proposal fit in Figure 1?

A. Dr. Milligan's proposal assumes that loss of load risk varies solely as a function of load, which is most comparable to the zero-percent solar penetration level on the far left side of the figure.

Q. Where does the solar penetration in the Company's 2019 IRP preferred portfolio fit in Figure 1?

A. The Company's existing resources combined with the 2019 IRP preferred portfolio results in 11.6 million MWh of utility-scale solar generation in 2030, and 59.2 million MWh of retail load, after accounting for cost-effective energy efficiency measures. That corresponds to a solar penetration level of roughly 20 percent, which is well beyond the level projected in the Company's analysis from 2018. Roughly one third of the 2030 solar generation in the 2019 IRP is already contracted and either operating or will be online by 2021. The Company has also signed several contracts for additional solar resources since the IRP was prepared that are not included in these numbers. Of the future solar resources identified in the 2019 IRP preferred portfolio through 2030, approximately 74 percent were projected to be online by the end of 2023 to qualify for higher investment tax credits, and all of the IRP solar resources included storage, which qualifies for the same investment tax credits as part of a solar facility. As a result, cost-effective solar resources are projected to form a big part of the Company's planned resources to serve customers.

Q. Given the results shown on Figure 1, does the capacity contribution of the incremental solar resources in the 2019 IRP preferred portfolio drop to zero?

A. Not necessarily. Just as completely ignoring resource mix produces an erroneous result, Figure 1 illustrates solar capacity contributions for the Company from a specific set of resource portfolios. In the Company's analysis, the incremental capacity contribution of solar resources was primarily measured through a reduction in the need for gas plants and had relatively few other moving components. The 2019 IRP preferred portfolio includes significant quantities of energy storage and wind resources that can complement solar, for example by providing energy later in the evening when solar does not generate. Complementary interactions result in a greater effective contribution than individual resources would have on their own.

Q. How did the 2019 IRP deal with the interactions between resource portfolios and reliable system operation?

A. During the development of the 2019 IRP the Company recognized that single capacity contribution values and stepped functions based on the penetration of a particular resource type were not ensuring reliable system operation in all cases. More importantly, the achieved level of reliability from case to case varied, making it difficult to compare the results. To fix this, PacifiCorp developed a Reliability Assessment during the 2019 IRP which evaluated the hourly resource availability and requirements of each portfolio, relative to a uniform reliability target. The Reliability Assessment recognizes that adequate resources must be available in every hour, and helps ensure that no hours are missed. To the extent a portfolio does not provide sufficient coverage of load and reserve requirements in all hours, the IRP model is directed to choose from simple cycle combustion turbines, energy storage, and energy efficiency to make up the difference.[15]

Q. Does Dr. Milligan criticize the Company's calculation of capacity contribution in the 2019 IRP?

A. Yes.[16]

Q. Does Dr. Milligan criticize the Company's capacity contribution analysis that was performed to assess the contributions to reliable operation of resources in the 2019 IRP preferred portfolio?

A. No.[17] Dr. Milligan criticizes the initial capacity contribution assessment used in portfolio development, but does not acknowledge a later capacity contribution assessment, also described in Appendix N of the 2019 IRP, which demonstrates how capacity contributions change as result of portfolio differences and which provides values that are aligned with the resources selected in the 2019 IRP preferred portfolio.

---

[15] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02. Volume II. Appendix R.
[16] *See* lines 429-433 of Vote Solar witness Dr. Milligan's Revised Testimony.
[17] *See* lines 423-427 of Vote Solar witness Dr. Milligan's Revised Testimony.

Q. Does Dr. Milligan acknowledge that the overall composition of a resource portfolio is important for ensuring reliable system operation?

A. Apparently not, as the methodology he advocates for, based on the highest load hours, is completely independent of resource portfolio.

Q. Does the Company's Reliability Assessment help ensure that portfolios achieve reliable system operation?

A. Yes.

Q. Is there any equivalent mechanism in Dr. Milligan's proposal to ensure that capacity contribution calculations achieve reliable system operation?

A. No.

Q. Does Dr. Milligan have any specific criticisms of the Company's capacity contribution analysis in the 2019 IRP?

A. Yes.[18] First, Dr. Milligan claims that the Company's method is less accurate than other simplified approximations to ELCC. Second, Dr. Milligan claims that the Company's hourly LOLP values are unlikely to represent periods of long-term risk.

Q. What support does Dr. Milligan provide for his claim that the Company's method is less accurate than other simplified approximations of ELCC?

A. Dr. Milligan cites a paper that he co-authored in 1997.

Q. Do you have concerns about the applicability of the 1997 study to the Company's current circumstances?

A. Yes. The study indicates that it relies upon one year of load and generator data from Tri-State Generation and Transmission, Inc. Given that this study was released in 1997,

[18] *See* lines 429-433 of Vote Solar witness Dr. Milligan's Revised Testimony.

the portfolio of generation resources on which it is based is necessarily more than twenty years old. Tri-State contracted for its first wind project in 2009, so it is unlikely that the generator data includes more than a de minimums quantity of wind, solar, or storage resources.[19] The resource portfolio is thus primarily composed of conventional thermal resources that are subject to random forced outages that are spread more or less uniformly across the year. As a result, conventional thermal resources will not drive LOLP into particular periods and LOLP occurrences will be closely aligned with the level of load in each hour.

Q. Does the addition of wind, solar, and storage resources impact the relationship between load and LOLP?

A. Yes. To the extent resource supply increases in some hours but not others, LOLP will shift away from the hours with the highest load and into hours with the highest net load, i.e. when fewer resources are available, which is not necessarily at the same time as peak load. To the extent that incremental resources add generation to periods where LOLP has already been reduced by the existing portfolio, their incremental contribution to reliable operation will be smaller.

Q. Has the Company noted relationships in the output of wind and solar resources across its system?

A. Yes. The Company has a large quantity of operating wind and solar resources in its portfolio. The output of these resources varies from day to day and from hour to hour, and resources of the same type (i.e. wind or solar) that are in close geographic proximity tend to have correlated output, i.e. they tend to deliver more when other resources of

[19] Denver Post. 7/6/2009. Available online at: https://www.denverpost.com/2009/07/06/tri-state-to-use-wind-farm-on-eastern-colorado-plains/ (accessed 6/16/2020).

their type in their area are also delivering more, and less when other resources of their type in their area are also delivering less.

Q. How does the Company model the relationships of wind and solar resources across its system?

A. The Company has relatively little history for solar resources, which have mostly come online since 2016. While a number of wind resources have been online for ten years or more, others have been added since then and thus have much less history. There may also be relationships between wind and solar generation that are not readily apparent. Given the complexity of the relationships between these resources and the lack of robust historical data, wind and solar generation profiles are modeled based on actual hourly generation data from a single historical calendar year, with adjustments to align with normal expected output. For resources that were not yet operating in the historical period, generation profiles are derived from the available hourly data from other resources of that type in the same vicinity, again adjusted to align with expected output.

Q. What does the prevalence of wind and solar resources in the Company's portfolio mean with respect to the results of Dr. Milligan's 1997 study?

A. The conclusions from Dr. Milligan's 1997 study have not been demonstrated to be appropriate for a system with the levels of wind and solar resources currently on the Company's system and planned to be added in the 2019 IRP. Given the Company's circumstances, the assumed superiority of a load-only analysis that disregards resource mix is highly questionable.

Q. Do you have concerns related to the use of the ELCC methodology in Dr. Milligan's 1997 study?

A. Yes. The ELCC methodology compares two scenarios: one with a utility's current portfolio and resources and one that adds the resource being evaluated along with enough additional load such the reliability is the same as that in the original portfolio. I have two concerns with the ELCC methodology, the first is related to load additions, while the second is related to the specific reliability metric employed.

Q. Does the Company anticipate ongoing additions of load into the foreseeable future?

A. No. The ELCC represents a scenario in which a utility's loads can "grow into" the incremental supply from particular resource options. However, in PacifiCorp's 2019 IRP, most load growth is forecasted to be offset by cost-effective energy efficiency resources.

Q. Does the Company still have appreciable resource requirements in its twenty-year planning horizon despite relatively stable loads?

A. Yes. While the available energy efficiency can help limit load growth, it is not sufficient to replace the energy and capacity provided by aging resources that are expected to retire. As a result of retirements, the Company will be significantly changing the composition of its portfolio, and has numerous options for doing so. However, given the scale of the resource changes that are necessary and the range of portfolio options, the Company's circumstances do not align well with the ELCC methodology's point estimate of capacity contribution based on a single resource portfolio.

Q. What is your second concern with the ELCC methodology as described in Dr. Milligan's 1997 study?

A. As a reliability measure, Dr. Milligan's 1997 study uses loss of load expectation, with a target of one day in ten years. The choice of a reliability measure impacts how loss of load events are prioritized. Employing a different reliability measure would result in a different capacity contribution using the ELCC methodology. Capacity contribution approximation methods also produce different results depending on the reliability measure used.

Q. Does the Company evaluate other reliability measures besides LOLE?

A. Yes. The Company conducted a Planning Reserve Margin study for its 2019 IRP.[20] That study describes how three separate measures of reliability are assessed:

- **Expected Unserved Energy ("EUE")**: Measured in gigawatt-hours ("GWh"), EUE reports the expected (mean) amount of load that exceeds available resources over the course of a given year. EUE measures the magnitude of reliability events, but does not measure frequency or duration.
- **Loss of Load Hours ("LOLH")**: LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. A LOLH of 2.4 hours per year equates to one day in 10 years, a common reliability target in the industry. LOLH measures the duration of reliability events, but does not measure frequency or magnitude.
- **Loss of Load Events ("LOLE")**: LOLE is a count of the expected (mean) number of reliability events over the course of a given year. An LOLE of 0.1

[20] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02. Volume II. Appendix I.

events per year equates to one event in 10 years, a common reliability target in the industry. LOLE measures the frequency of reliability events, but does not measure magnitude or duration.[21]

Q. Why are multiple reliability measures appropriate?

A. The three reliability measures quantify loss of load events in terms of magnitude, duration, and frequency. Together, these measures provide a more complete picture of loss of load conditions than considering only LOLE.

Q. Is one measure the "right" measure?

A. No. Dr. Milligan notes that the "capacity contribution metric recommended by the North American Electric Reliability Corporation ("NERC") is the effective load carrying capability ("ELCC") metric or a similar variant that is based on loss-of-load probability or related metric"[22] (emphasis added). This leaves individual utilities to determine their tolerance for different types of potential loss of load conditions.

Q. Are there reasons why LOLE may not be preferable as a reliability target?

A. Yes. LOLE focuses on the number of events. Under an ELCC calculation using LOLE, resources receive capacity credit for eliminating events, which is easiest for events with the smallest magnitude and duration. Because events with a large magnitude or long duration are difficult to eliminate completely, a single resource that reduces the duration or magnitude of the largest events may not receive any capacity credit despite delivering during a loss of load event.

[21] *Ibid*.
[22] *See* lines 379-382 of Vote Solar witness Dr. Milligan's Revised Testimony.

Q. Is the focus of the LOLE-based ELCC calculation on the smallest events problematic for the Company's analysis?

A. Yes. The smallest events in an ELCC calculation are transitory and can be eliminated by relatively small resource additions. Once an event is eliminated as a result of resource additions, any additional resources delivering during the time period in which the event previously occurred will no longer receive a capacity credit during that time period. This results in capacity credit values that change rapidly as additional resources are added.

Q. Does the focus of the LOLE-based ELCC calculation on the smallest events influence the results reported in Dr. Milligan's 1997 study?

A. It is likely that the focus on the smallest events contributes to the measured "improvement" in accuracy when a relatively large percentage of the top load hours is used, as adding lower-risk hours that can be converted to no-risk hours provides the largest LOLE-based ELCC improvement. Similarly, an equal weighting of a large number of hours, rather than a weighting based on load or risk provides a measurable "improvement" since it increases the credit applied to lower-risk hours that are most likely to register as an improvement in the LOLE-based ELCC calculation.

Q. Dr. Milligan proposes using the top 10 percent of load hours, or 876 per year for an approximation of ELCC. How does this compare to the risk of loss of load events in the analysis performed for the Company's 2019 IRP?

A. In the final capacity contribution analysis prepared for the 2019 IRP, the Company performed a study with 500 iterations of load, hydro, and thermal outage conditions, based on a portfolio for the year 2030 that is very close to the 2019 IRP preferred portfolio. In that study, only 278 hours were identified as a loss of load risk, significantly fewer than the 876 used in Dr. Milligan's analysis.

Q. When using a weighted-LOLP capacity factor approximation method, as the Company did in the 2019 IRP, which loss of load conditions are emphasized?

A. The weighted-LOLP capacity factor approximation method places greater weighting on the hours when outages are most likely to occur. Those hours also generally have outages with above average levels of energy not served. More frequent outages generally indicate that a wider range of conditions would lead to shortfalls, for instance two thermal unit outages combined with loads that are slightly above normal. Hours in which outages are less frequent are more likely the result of several thermal unit outages plus loads that are well above normal, conditions which are less likely to occur in conjunction.

Q. How big of a difference does the use of weighted and unweighted LOLP values make?

A. Using Dr. Milligan's proposed top 10 percent of load hours, every hour is equally weighted with 1/876th of the capacity available. Using the Company's weighted-LOLP approach, the hour with the highest risk of outages was assigned over 10 percent of the capacity available.

Q. Did the hour with the highest risk of outages have one of the highest loads?

A. No. The hour with highest risk of outages in the Company's analysis was in August, rather than July when the Company typically has its annual peak load. It is also not even the highest load for the day it occurred, as it is in the evening while the peak load is typically in the late afternoon. In the load data used by Dr. Milligan, the hour with the highest risk of outages would only have ranked 742nd.

Q. Assuming the export credit profile was considered a firm commitment, what capacity contribution value would be assigned using the methodology in the Company's 2019 IRP?

A. Comparing Vote Solar's export profile to the 12x24 weighted loss of load probability data from the Company's 2019 IRP results in a capacity contribution of 3.7 percent. After accounting for avoided losses, the capacity contribution increases to 4.1 percent. This value does not account for variations within each month, for instance the fact that exports are lower when a customer's own load is high. As a result, the effective contribution of exports is likely lower.

Q. Do any other capacity contribution methods produce comparable values for CG exports?

A. Yes. Dr. Milligan's proposal to compare CG exports to the top 10 percent of load hours is deficient because it does not account for variations in resource supply from hour to hour while Figure 1 demonstrates that the level of solar penetration has a significant impact on its capacity contribution. This can also be illustrated with actual load and solar data from 2019. As previously noted, the average availability of CG exports during the top 10 percent of Utah load hours in 2019 was 22 percent. If this calculation is repeated using Utah load net of the actual hourly output of the Company's solar resources in Utah during 2019, the average availability of CG exports drops to 12 percent. The Company had approximately 850 MW of solar resources in Utah during 2019, and has executed contracts for nearly 700 MW more. Grossing up the 2019 hourly solar data by approximately 1.8 times to account for this capacity that is not yet online drops the average availability of CG exports to 4.1 percent. After accounting for avoided losses, the capacity contribution increases to 4.6 percent. This does not account for the over 1,000 MW of additional utility-scale solar resources in Utah included in the 2019 IRP preferred portfolio in the next ten years.

Q. What is your conclusion with regard to the capacity contribution of CG exports?

A. Both the methodology from the 2019 IRP and a methodology based on actual load net of actual solar generation result in a capacity contribution for CG exports of around 4 percent. Under both methodologies the timing of CG exports does not align well with periods in which there is a significant risk of loss of load events as a result of the Company's large portfolio of solar assets. As a result, the capacity contribution of CG exports is projected to decline or remain low over time as the Company's portfolio of solar assets grows. In addition, it is inequitable for non-participating customers to pay for capacity on output that is prioritized to another offtaker (i.e. the customer generator's own load) and for which there is no commitment to deliver. This is particularly true for future customers on Schedule 137 who are likely to have a significant incentive to offset their own retail consumption, rather than export to the Company. Because the Schedule 135 and 136 customers that form the basis for the current export profiles do not face a significant incentive to shift their retail consumption, as their export compensation is similar to retail rates, they may not be representative of future customers under Schedule 137.

Avoided Generation Capacity Costs

Q. Do parties propose that CG exports should be credited for avoiding generation capacity?

A. Yes. Both Vivint Solar and Vote Solar propose that CG exports should be compensated for avoiding generation capacity. This section discusses the cost component of avoided generation capacity value.

Q. What are the capacity cost values proposed by parties?

A. Vivint Solar proposes a capacity cost based a new gas peaking resource, which works out to approximately $77/kW-yr.[23] Vote Solar proposes a capacity cost based on the duct firing component of a combined cycle combustion turbine, with a cost of approximately $36/kW-yr.[24]

Q. How do these values compare to the current fixed resource costs in the Proxy/Partial Displacement Revenue Requirement ("PDDRR") methodology approved for determining avoided cost pricing for qualifying facilities?

A. The PDDRR methodology uses fixed costs from resources selected in the Company's most recently filed IRP preferred portfolio. Base load resources are assumed to defer the next thermal resource, which is currently a simple cycle combustion turbine at the Naughton site coming online in 2026 with a fixed cost of $88/kW-yr (2026$).[25] Solar resources are assumed to defer the next solar resource, currently a solar combined with

[23] *See* lines 188 through 189 of Vivint Solar witness Mr. Worley's Direct Testimony. $825/kW * 9.39% = $77.46/kW-yr.
[24] *See* lines 547-561 of Vote Solar witness Dr. Milligan's Revised Testimony. See also Dr. Milligan's workpaper "CONFIDENTIAL 17-035-61 Phase 2 Vote Solar Workpapers 1-MM Worksheet 5-8-2020 Milligan REVISED", tab "Capacity Resource Proxy", cell B32.
[25] *See* April 9, 2020 filing in Docket 20-035-T04. RMP Attachment 7, tab "Table 3 185 MW (NTN) 2026)", cells D24 and E24.

storage resource located in northern Utah and coming online by the end of 2023 with a fixed cost of $93/kW-yr (2024$).[26]

Q. Are capacity costs equal to fixed resource costs?

A. No. Under the PDDRR methodology, when a QF is compensated for the costs of a resource, that resource is also removed from the Company's portfolio. As a result any generation or operating reserves it was providing need to come from another source. While the variable costs associated with the displaced resource are also removed, the net impact is an increase in costs because Company-owned assets are dispatched based on economics, so the next best alternative will have a higher cost. As a result, the effective "capacity cost" is the fixed cost of a deferred resource, net of the energy value and other benefits that resource provides.

Q Do the current assumed resource deferrals have significant energy value?

A. Yes. In the studies supporting the QF avoided costs, the 2026 SCCT at Naughton operates at an average capacity factor of 26 percent between 2026 and 2038, indicating there are many hours in which it can be dispatched economically. Similarly, the Utah North solar and storage resource has an annual solar capacity factor of approximately 30 percent, plus a storage resource that can provide four hours of output during the hours with the highest value each day. As a result both of these resources are providing significant energy value.

Q. Do parties account for the energy value in their proposed capacity costs?

A. No. Vivint Solar makes no attempt to identify the energy value associated with its proposed capacity costs.[27] Vote Solar indicates that it attempted to isolate the

---

[26] *See* April 9, 2020 filing in Docket 20-035-T04. RMP Attachment 5, tab "Table 3 PV wS UTN_2024", cell J18.
[27] *See* lines 185 through 194 of Vivint Solar witness Mr. Worley's Direct Testimony.

contribution of capacity by selecting a low-cost capacity resource,[28] but does not quantify the energy benefits associated with its selection.

Q. Are energy and capacity assumptions related?

A. Yes. In the approved PDDRR methodology, the lost energy benefits of a deferred capacity resource and the added energy benefits of an incremental resource are assessed at the same time, using the same inputs and assumptions. In this instance, Dr. Milligan has proposed using forward market prices to value the energy associated with CG exports. As a result, the lost energy benefits of his selected capacity resource should be assessed on the same basis.

Q. Have you assessed the energy value of duct firing resource Vote Solar used to identify a capacity value?

A. Yes. This resource has an expected heat rate of 8,027 Btu/kWh, and operates using natural gas. In addition to the electricity prices used by Dr. Milligan, the Company's OFPC includes forward natural gas prices. The electricity and gas prices are related, as the marginal cost of gas resources contributes to the market-clearing price for electricity in many hours. Based on the cost of gas in the Company's OFPC and Dr. Milligan's proposed energy values, the gas resource identified by Vote Solar would be economic to operate in an average of 81 percent of all hours in each year from 2021 through 2040. During the hours it is economic it would generate energy revenue that exceeds its variable costs, and that margin would exceed the $36/kw-year capital cost proposed by Dr. Milligan and pay for itself several times over. As a result the net cost of capacity

[28] *See* lines 543-566 of Vote Solar witness Dr. Milligan's Revised Testimony.

for this resource would be zero and no compensation for capacity would be necessary given Dr. Milligan's proposed energy valuation.

Q. Why isn't the IRP preferred portfolio composed solely of duct firing resources similar to that proposed by Dr. Milligan?

A. There are several reasons. First, a duct firing resource can only be added to supplement the capability of a combined cycle combustion turbine facility built at the same time. The underlying combined cycle combustion turbine has higher efficiency as well as significantly higher fixed costs. As a result, selecting the duct firing component on its own is not an option. Second, there are operational constraints related to the interaction between the combined cycle combustion turbine and its duct firing capability. The duct firing capability can only be deployed when the main unit is online and generating at maximum. Third, the fact that the IRP did not select any duct firing resources indicates that other resource alternatives and combinations produce greater benefits relative to their fixed costs. Finally, the IRP does not assume that all generation can be sold at market prices, and instead calculates value of individual assets within an entire portfolio of resource and transmission options. By viewing capacity and energy valuation in isolation from each other and in isolation from other resource and transmission options and interactions, Dr. Milligan's proposal fails to realistically represent the Company's avoided costs.

Q. Do you have any other concerns related to the capacity costs reported by parties?

A. Yes. Both Vivint Solar and Vote Solar use an annual carrying charge of 9.39 percent to allocate assumed capital costs to a single year. This value is derived from the Company's 2018 Marginal Cost Study filed in California, which is now over two years old. In the Company's ongoing general rate case in Utah, the equivalent value is now 7.82 percent[29], as a result of a lower return on equity and a lower cost of debt. This represents a 17 percent reduction in costs from that proposed by these parties.

Q. Are carrying charges from marginal cost studies appropriate for determining avoided costs?

A. No. A marginal cost of service study is intended to produce a reasonable revenue requirement allocation amongst customer classes and includes an assumed asset life of 20 years. It does not represent the cost the Company would use to justify acquiring an asset, and it does not represent the cost the Company would recover from customers for providing service from that asset. In both long-term planning and cost recovery, the expected life specific to an asset would determine the annual carrying charge.

Q. What carrying charges are used for long term planning and avoided costs?

A. The carrying charges used in the Company's IRP are published in the supply-side resource tables that identifies potential future resource options (and which were relied upon by Dr. Milligan to identify his chosen capacity resource).[30] The duct firing component of a combined cycle combustion turbine selected by Dr. Milligan from the Company's 2019 IRP has an assumed life of 40 years and a carrying charge of 6.79 percent, while the SCCT at Naughton used in some avoided cost calculations has an assumed life of 35 years and a payment factor of 6.96 percent. As a result, the carrying charges for these resources are significantly lower than the value of 9.39 percent proposed by parties.

[29] *See* Docket No. 20-035-04. Direct Testimony of Robert Meredith. RMP Exhibit (RMM-15). Table 6.
[30] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02. Volume 1. Tables 6.1-6.2.

Q. What do you recommend with regard to carrying charges?

A. It is more reasonable to align with the assumptions made for long term planning in the Company's 2019 IRP than with assumptions used for the purpose of retail customer class cost allocation that were used in California.

Q. What is your conclusion with regard to capacity costs overall?

A. The Company's PDDRR methodology provides the most accurate estimate of the capacity and energy value of new resources. While not exactly the same as CG exports, the standard avoided cost prices for fixed-tilt solar resources in Schedule 37 provide a reasonable starting point for determining the value of both capacity and energy from CG exports. The approved Schedule 37 prices do not indicate a significant capacity value for fixed-tilt solar resources, and the capacity value of CG exports would be diminished further as a result of customer's onsite consumption. In any case, given the absence of a commitment to deliver on the part of customer generators, it is not appropriate to compensate them for avoided capacity costs.

Avoided System Losses

Q. What are parties' proposals for avoided system losses?

A. Vote Solar witness Mr. Volkmann proposes loss expansion factors of 9.08 percent for generation and transmission, 8.621 percent for energy, and 4.624 percent for distribution.[31] Vivint Solar witness includes an adjustment for the value of losses but does not gross-up metered export volumes for system losses.

Q. What is the basis for Mr. Volkmann's proposed losses?

A. The values referenced by Mr. Volkmann are directly from the Company's loss study.

[31] *See* lines 263 through 266 of Vote Solar witness Mr. Volkmann's Revised Affirmative Testimony.

Q. What does the Company's loss study report?

A. The Company's loss study identifies the losses as a function of deliveries to loads connected at different levels of the electrical grid, ranging from transmission substations with voltages that could be up to 500 kV to the secondary distribution system delivering to homes and small business at voltages from 120 V to 480 V.

Q. What is the purpose of the Company's loss study?

A. The Company's loss study estimates losses related serving retail load that is served at different voltage levels.

Q. Are line loss values applicable to load also applicable to CG exports?

A. No. The expected profile of CG exports varies significantly from the retail load profile for residential and small commercial customers. As a result, the avoided losses averaged across periods when CG exports are delivered will not be the same as the losses averaged across retail load. Mr. Volkmann acknowledges this, noting that load losses increase exponentially as load increases.[32]

Q. Is there another difference between the losses attributable to retail load and those avoided by CG exports?

A. Yes. The losses attributed to retail load are an average for all load, while it is appropriate to consider marginal losses for CG exports. The exponential increase in losses as load increases results in increasing marginal line losses, and the last few kW of deliveries that are actually avoided by CG exports avoid losses that are higher than what ends up being delivered. As a result, marginal losses are generally higher than average losses, especially under peak load conditions. However, this effect is partially offset by no-

[32] *See* lines 214 through 217 of Vote Solar witness Mr. Volkmann's Revised Affirmative Testimony.

load losses, which are fixed regardless of load level, and thus cannot be avoided by CG exports. Removing no-load losses results in marginal losses that are below average losses in hours when load is relatively low.

Q. Did Mr. Volkmann account for the differences between delivery profiles or average and marginal losses?

A. No.

Q. Did the Company's proposal include a line loss calculation that accounts for the difference between the delivery profiles of CG exports and retail load and the difference between average and marginal losses?

A. Yes.[33]

Q. Does any aspect of Mr. Volkmann's proposal mirror that of the Company's proposal?

A. Yes. Mr. Volkmann has proposed that CG exports avoid losses on the transmission and primary distribution systems.[34] The Company's proposal reflects avoided losses over the same system components, from the transmission system through the primary distribution system.[35]

Q. What do you recommend with regard to the calculation of avoided line losses for energy and generation capacity?

A. The Company's proposal included avoided energy losses as described above. The same methodology can also be applied to generation capacity estimates. As previously discussed, Vote Solar's CG export profile produced a 3.7 percent capacity contribution

---

[33] *See* lines 135 through 153 of Rocky Mountain Power witness Mr. MacNeil's Direct Testimony.
[34] *See* lines 258 through 260 of Vote Solar witness Mr. Volkmann's Revised Affirmative Testimony.
[35] *See* lines 135 through 153 of Rocky Mountain Power witness Mr. MacNeil's Direct Testimony.

under the methodology from the Company's 2019 IRP, relative to the alternating current ("AC") rating of customer generation equipment. Grossing up CG export volumes using the Company's marginal line losses more accurately reflects the magnitude of the impact on the Company's generation dispatch and generation capacity needs, and results in a 10 percent increase in capacity contribution, to 4.1 percent of the generator's AC rating. This value does not account for the fact that exports are lower when a customer's own load is high. As a result, the effective contribution of exports is expected to be lower.

Q. How do avoided losses impact transmission and distribution capacity requirements?

A. The Company's marginal line loss calculations provide a reasonable estimate of the magnitude of the impact on system requirements, relative to CG exports metered at secondary voltages. Details on transmission and distribution system capacity deferral associated with CG exports are addressed by Rocky Mountain Power witness Jacob Barker.

Avoided Fuel Hedging/Financial Risk

Q. What are parties' proposals for avoided fuel hedging and financial risk?

A. Vote Solar witness Dr. Berry claims that CG exports replace natural gas-fired generation, and thus reduce exposure to natural gas price volatility.[36] Dr. Berry also claims that the reduction in demand for natural gas and electricity purchases "can reduce the market prices of these commodities allowing RMP to purchase them at lower prices."[37]

[36] *See* lines 512 through 515 of Vote Solar witness Dr. Carolyn Berry's Revised Affirmative Testimony.
[37] *See* lines 515 through 517 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.

Q. Is Dr. Berry's proposal consistent with the other export credit value elements proposed by Vote Solar?

A. No. While Dr. Berry claims a benefit associated with reductions in the Company's natural gas demand, Vote Solar witness Dr. Milligan has proposed avoided energy costs based on the Company's forecast of forward electricity market prices.[38] There are several key aspects of Dr. Milligan's assumptions that conflict with Dr. Berry's proposal. First, no fuel savings should be assumed, since Dr. Milligan is assuming CG exports impact electricity market volumes. Second, Dr. Milligan is using forward electricity market prices that already reflect a premium to account for uncertainty in future conditions, as opposed to a forecast of spot electricity market prices based on a specific set of conditions. Finally, Dr. Milligan indicates that the Company could be either a buyer or seller of electricity associated with CG exports.[39] To the extent CG exports result in increased market sales, any market price reduction would reduce sales revenue not only for the CG export volumes, but also for the volumes the Company already had available to sell.

Q. Dr. Berry cites an estimated fuel price hedging benefit of $26/MWh from a 2014 study. Have any important factors changed since that time?

A. Yes.[40] Since 2014, the Company has added over 1,150 MW of utility-scale solar resources to its system, as well as a significant quantity of customer-sited sources. This reduces the coincidence of customer generation with peak needs and also depresses prices during periods when the sun shines, in exactly the manner described by

[38] *See* lines 179 through 185 of Vote Solar witness Dr. Milligan's Revised Affirmative Testimony.
[39] *See* lines 195 through 201 of Vote Solar witness Dr. Milligan's Revised Affirmative Testimony.
[40] *See* lines 526 through 527 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.

Dr. Berry. Market prices have already been depressed significantly during the day as a result of changes in the Company's portfolio. This is without accounting for significant solar resource additions by other utilities around the west, all of which reduce demand for resources during the middle of the day when CG exports are highest. The CAISO has described this effect as the "duck curve" and plotted the evolution over time.[41] These effects were illustrated in Figure 1 of my direct testimony, based on historical EIM operations from the 36 months ending October 2019.[42] To the extent solar resource additions continue to be added, the relative value during daylight hours will likely decline further.

Q. Are there low cost opportunities to hedge fuel and market price risk besides CG exports?

A. Yes. The cost of utility-scale solar assets has declined significantly in the past few years and is projected to continue falling. This has contributed to cost-effective utility-scale solar assets being included in the Company's preferred portfolio in its last two IRPs. Utility-scale solar assets provide energy and generation capacity that is in some respects more valuable than CG exports, since it does not get consumed in meeting a customer's own load and thus covers a broader portion of the day.

Q. Are there significant downsides to a hedge for an extended term, such as the 25 years proposed by Vote Solar?

A. Yes. While the Company competitively procures resources under long term contracts and through acquisitions, its Hedging Policy only calls for forward transactions to

---

[41] CAISO Fast Facts: What the duck curve tells us about managing a green grid. Available online at: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf (accessed 7/6/2020).
[42] *See* lines 191 through 193 of Rocky Mountain Power witness Mr. MacNeil's Direct Testimony.

reduce the risk of electricity and natural gas market price movements in the next 36 months. Over a longer term, a wider range of steps can be taken to cost-effectively reduce electricity or natural gas demand in response to market price movements, including renewable resource procurement, fuel-switching, and energy efficiency programs. Locking in gas costs over a longer period reduces the opportunity for customers to benefit from alternatives that become available at a later time.

Q. What do you recommend with regard to the value of avoided fuel hedging and financial risk?

A. The Company's proposed avoided energy costs are derived from a GRID model result which reflects the Company's Official Forward Price Curves for natural gas and electricity. As a result, it already captures a premium on these commodities relative to spot prices. That premium is also already reflected in the avoided energy cost proposal of Dr. Milligan, which reflects the Company's Official Forward Price Curves for electricity. As a result, no adjustment for avoided fuel hedging and financial risk is appropriate under either proposal. Furthermore, given expected declines in solar resource costs, as well as resource additions driven by renewable energy credit demand, there is significant risk that market prices during the day will be lower than what is reflected in the Company's Official Forward Price Curve, even without solar resources being added to the Company's system. In the absence of a competitive procurement with detailed review of a range of future conditions, a long term fixed commitment is inappropriate, especially when customers are not making a reciprocal commitment in return, as in the case of the proposed CG export program.

Avoided Ancillary Services

Q. What do parties recommend with regard to the ancillary services associated with CG exports?

A. Vote Solar witness Dr. Berry notes that there is ongoing debate around whether distributed solar resources will provide or require additional ancillary services at various penetration levels and indicates that the value may grow over time, especially if coupled with complementary technology.[43] Vote Solar witness Mr. Volkmann also describes "integration" costs associated with distribution system upgrades to accommodate increasing levels of rooftop solar; however, this is related to the fixed costs and capabilities of the distribution system, rather than ancillary services.

Q. What adjustments for ancillary services are included in the Company's proposal?

A. The Company includes a solar integration cost of $0.15/MWh in 2021, consistent with the results of the Company's Flexible Reserve Study in its 2019 IRP.[44] "Integration" in this instance refers to the opportunity cost of keeping flexible resources available that can accommodate fluctuations in load and resources between an hour-ahead forecast and actual conditions. This is also referred to as regulation reserve. The Company's GRID modeling also attributes a 3 percent contingency reserve obligation to generation resources, including CG exports.[45] The associated requirements are incorporated in the GRID model redispatch, and the cost is reflected in the Company's energy price results.

---

[43] *See* lines 493 through 505 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.

[44] *See* lines 161 through 166 of Rocky Mountain Power witness Mr. MacNeil's Direct Testimony.

[45] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02. Volume II, Appendix F: Flexible Reserve Study. Page 80. Available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf.

Q. Under what conditions would distributed solar resources be likely to provide ancillary services?

A. In general, ancillary services require adjustments in power output in response to specific local or system conditions. Absent a storage component, a solar resource that is delivering all of its output to the grid would not have the ability to increase output on demand. Because solar resources have no variable cost, they are not typically economic to provide ancillary services like operating reserves unless marginal energy costs are zero or below zero. To be able to provide operating reserves, a communication and control system would be needed that could rapidly dispatch a resource up and down in response to automated signals from the system operator. Many of the Company's wind resources already have such capability, as will contracted solar resources coming online this year. All of the proxy wind and solar assets available for selection in the 2019 IRP were assumed to be capable of curtailing their output and providing operating reserves. As a result, when marginal prices drop to zero, there are a likely to be a number of resources that could provide operating reserves at little or no cost, so the opportunity cost of providing ancillary services is also likely to be zero.

Q. Would ancillary services provide incremental value relative to the other elements already identified?

A. The ability to curtail CG exports could potentially provide a small amount of additional value in the GRID model results for avoided energy value; however, it is unlikely that the communications systems necessary to achieve that capability would be cost-effective given the limited frequency it would be deployed and low margins when it is deployed, relative to other resource options. Under Dr. Milligan's proposed avoided energy values, energy prices never drop to zero or below, so there would be no periods in which ancillary services from a zero-variable cost resource would be economic.

Q. What do you recommend with regard to avoided ancillary services?

A. The Company's proposal reasonably accounts for the ancillary services provided for CG exports. At this time, CG exports are not anticipated to be under the Company's control, and no mechanism for such control is present in the proposed program. To the extent complementary technologies and control mechanisms become available, it would be appropriate to address avoided ancillary services specific to individual technologies and circumstances at a later date.

Reliability and Resilience

Q. What values do parties identify for reliability and resilience from customer generation?

A. Vote Solar witness Dr. Berry identifies an estimated value of $20/MWh, based on a 2012 study from the east coast, but does not propose a specific value as part of this proceeding. [46]

Q. Does the value in the referenced 2012 study overlap with the Generation Capacity element previously discussed?

A. Yes. The 2012 study assumes that the availability of solar is higher during heat-wave driven extreme conditions and that its effective load carrying capability would be understated as a result. To the extent the effective load carrying capability was measured accurately, no adjustment would be appropriate.

[46] *See* lines 632 through 645 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.

Q. Is the availability of the CG export program higher under extreme conditions, like the distributed solar resources contemplated in the 2012 study?

A. No. Under extreme heat conditions, a higher than average portion of CG production would be devoted to a customer's own needs, resulting in less available for the CG export program.

Q. Is the value in the referenced 2012 study included in the rates paid by non-participating customers?

A. No. The 2012 study notes that the costs quantified for this element are not the responsibility of ratepayers, and instead reflects the costs to society of lost goods and business, compounded impacts on the economy and taxes due to power outages.

Q. Is backup generation that is available to an individual customer during power outages an appropriate system cost for inclusion in a CG export credit?

A. No. To the extent customers receive electrical service from the Company and are economically rational, they are necessarily going to derive greater benefit from taking service than they would from not taking service, and will be worse off during power outages. If that were not the case, they would be better off operating completely off the grid.

The reliability of the electric grid is inherently decided at the system level through regulation and planning, and is necessarily a balance of cost and reliability, as a perfectly reliable system would be infinitely expensive. A customer that values reliable operation more highly than the system standard can seek out their own backup equipment if the cost of outages to them is high enough to justify the expense. It would be contrary to ratemaking principles for backup equipment serving the needs of an individual customer during outage conditions to be paid for by other customers who don't receive those outage reduction benefits.

Term of Export Credit Rate

Q. What do parties propose with regard to the fixed price term for the export credit program?

A. Utah Clean Energy[47], Vivint Solar[48], and Vote Solar[49] all recommend that export credit prices be fixed for twenty years.

Q. Does the Company already offer a long-term fixed price for resources that are comparable to customer generation?

A. Yes. The Company already offers a 15-year fixed price option for fixed-tilt solar resources under Utah Schedule 37. While Schedule 37 applies to qualifying facilities, it could be used to inform rates for an export credit rate schedule. After grossing up the approved Schedule 37 prices by 10 percent to account for avoided losses associated with rooftop systems, the 15-year nominal levelized price would be approximately $16/MWh, somewhat less than the Company's export credit proposal for 2021 in this proceeding. This price includes both energy and generation capacity consistent with the entirety of a fixed-tilt resource's output, so it would be less appropriate to apply to exported output only, particularly on a non-firm basis without a delivery commitment. Given that a significant proportion of the value to a customer generator under the Company's proposed Schedule 137 tariff is derived from reducing their utility

---

[47] *See* lines 333 through 346 of Utah Clean Energy witness Ms. Bowman's Direct Testimony.
[48] *See* lines 57 through 62 of Vivint Solar witness Mr. Worley's Direct Testimony.
[49] *See* lines 359 through 364 of Vote Solar witness Ms. Kobor's Revised Affirmative Testimony.

deliveries and avoiding retail rates, it should not be surprising that a commitment to sell at wholesale avoided costs would provide less benefit.

Q. Does the Company offer long-term fixed price commitments to non-participating customers?

A. No. The Company's rates are subject to change in rate cases and other ratemaking proceedings, as are billing determinants and rate structures. While gradualism is an important principle in ratemaking, it will necessarily be weighed against cost-causation considerations.

Climate and Environmental Impacts

Q. What climate and environmental values do parties propose?

A. Dr. Berry proposes a value related to the health benefits of reduced fossil-fuel generation[50] as well as a value for reduced carbon dioxide emissions.[51] Dr. Berry's calculation incorporates fossil-fuel emissions rates prepared by Dr. Milligan.[52]

Q. What carbon dioxide emissions rate is proposed by Vote Solar?

A. Dr. Milligan estimates that the carbon dioxide emissions rate of the Company's thermal fleet is approximately 0.98 tons per MWh in 2021. For the purpose of determining avoided emissions, Dr. Milligan also assumes that every MWh of CG exports and associated avoided losses avoids a MWh of thermal generation.

Q. Does Dr. Milligan's estimated carbon dioxide emissions rate decline over time?

A. Yes, somewhat. Dr. Milligan calculates the average emissions rate for the Company's thermal fleet over time by removing coal units that are assumed to have retired.

[50] *See* lines 705 through 715 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.
[51] *See* lines 746 through 767 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.
[52] *See* lines 569 through 622 of Vote Solar witness Dr. Milligan's Revised Testimony.

Removing coal plants with relatively high emissions results in a declining average emissions rate, as natural gas plants with lower emissions rates become a larger portion of the total. By 2038, Dr. Milligan assumes avoided emissions of 0.82 tons of carbon dioxide per MWh of CG exports.

Q. Does Dr. Milligan provide a reasonable estimate of the reduction in the Company's carbon dioxide emissions resulting from CG exports?

A. No. Dr. Milligan has estimated the average emissions rate for the Company's entire thermal fleet based on historical capacity factors and assumed that every CG export results in a pro-rata reduction to all thermal units. In actual operations, CG exports could result in reductions in market purchases or increases in market sales that would not result in changes in the emissions from the Company's thermal fleet. Dr. Milligan's estimate also ignores the impact of changes in unit dispatch levels on heat rates, which vary across a unit's dispatchable range. In general, thermal units are the least efficient at their minimum output and most efficient near their maximum output. As a result, the fuel that can be saved by operating a unit at a lower level of output is generally less than the average heat rate. Finally, Dr. Milligan's method disregards the fact that the Company dispatches its thermal resources based on economics, such that CG exports would reduce the emissions from the most expensive unit that would otherwise have been called upon.

Q. Is Dr. Milligan's proposal consistent with his other export credit value proposals?

A. No. Dr. Milligan's energy valuation assumes that 100 percent of the CG exports will be sold at the electricity prices in the Company's Official Forward Price Curve. Because the Company dispatches its resources economically, thermal resources will generally only be dispatched up when their operating costs are less than the market price. As a result, compensation based on market prices will be higher than the variable cost of thermal resources. Given that Dr. Milligan's energy valuation does not assume any impact to thermal output, it would be inappropriate to account for emissions savings that only result from changes in thermal output.

Q. Does the Company's proposed energy value assume that fossil-fuel generation will be reduced?

A. Yes. The Company's avoided energy costs for CG exports reflect GRID model results. That analysis indicates that 73 percent of the CG export volume would result in reduced thermal resource dispatch, with the remainder primarily impacting market transactions. The resulting avoided carbon dioxide emissions amount to approximately 0.69 tons of carbon dioxide per MWh of metered CG exports in 2021.[53]

Q. Why does the Company's proposal result in fewer avoided emissions?

A. The Company's analysis reflects the impact of CG exports on the marginal resource, and a portion of the time that marginal resource is either a market purchase or a sale, with no impact on the Company's carbon dioxide emissions. The Company's analysis also accurately reflects the marginal thermal unit, and the marginal heat rate impact of changes in generation dispatch.

[53] Carbon dioxide emissions are reported in the GRID model results. See rows 1174 through 1208 of tab "Delta" in the confidential workpaper "UT136 Export Credit - GRID AC Study CONF _2020 01 30.xlsm" provided with the Company's February 3, 2020 filing.

Q. What cost did Vote Solar apply to CG exports for avoided carbon dioxide emissions?

A. Vote Solar witness Dr. Berry includes both avoided compliance costs and social benefits in developing credits for avoided carbon dioxide emissions that total to a levelized value of approximately $94/MWh.[54] This is the average cost for the Company's fleet, with a cost of approximately $118/MWh for coal plants, and $45/MWh for gas plants.

Q. Did the Company include a cost related to carbon dioxide emissions in its export credit proposal?

A. No. The Company's Utah customers are not presently responsible for costs associated with carbon dioxide emissions, except to a limited extent when units are economically dispatched into the CAISO, in which case those costs are accounted for in market pricing and dispatch decisions. There are no rules or laws in place which would result in Utah customers becoming responsible for costs associated with carbon dioxide in the future, and in particular during the 2021 export credit study period. As a result, it would be inappropriate to include a credit for avoided carbon dioxide emissions as part of the CG export program at this time.

Q. If the Company did incur costs related to the carbon dioxide emissions of its thermal fleet, would those costs be strictly additive to the energy costs and avoided emissions in the Company's GRID model analysis of CG exports?

A. No. The Company economically dispatches its resources to provide reliable service to its customers at the lowest possible cost. The Company's GRID model analysis did not

[54] *See* lines 761 through 763 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.

include a cost on carbon dioxide, since the Company is not currently subject to one. If one was applied, the GRID model would have re-dispatched the system, moving to the most cost-effective resources under the new assumptions, inclusive of the cost of emissions. For example, gas units with a relatively low emissions cost could be dispatched ahead of coal units with a relatively high emissions cost that would otherwise have been economic. Similarly, market purchases could become more economic than the fuel and emissions costs of the marginal thermal unit in some periods. As a result, avoided emissions and the associated costs would be lower.

Q. With an emissions cost as dramatic as that proposed by Dr. Berry, would it be appropriate for the Company to pursue alternative resources to provide reliable service to its customers at the lowest possible cost?

A. Absolutely. A key part of the Company's IRP process is to evaluate a range of future conditions, and that has included a range of carbon dioxide emissions costs which can driver the selection of resources with low or no emissions. The Company also prepares portfolios built around high-cost views of future carbon dioxide prices to see what types of resources might be economic to pursue in the future. The resources selected in the 2019 IRP preferred portfolio were optimized relative to a medium view of future carbon dioxide prices which is well below that proposed by Dr. Berry. In the face of Dr. Berry's environmental cost of $118/MWh for coal generation, the Company would rapidly move to procure and deploy more cost-effective alternatives as quickly as possible, and would dramatically reduce coal dispatch. Because the emissions rates and assumptions underlying Dr. Berry's proposal completely ignore the Company's response to the conditions proposed, they would result in non-participating customers vastly overpaying for the cost of emissions reductions that could be achieved more cost-effectively through other means.

Q. What do you recommend with regard to the climate and environmental values proposed by Vote Solar?

A. Vote Solar's proposed climate and environmental values are overstated and should be rejected. The Company's Utah customers are not presently responsible for costs associated with carbon dioxide emissions that would be avoided as a result of CG exports. While such costs could be implemented in the future, they are highly uncertain. In addition, the Company's response to adapt its system to such costs would reduce the impact on customer rates, as non-emitting resource options which are not economic under current price-policy conditions would become more economic if high carbon dioxide emissions costs were enacted.

Conclusion

Q. Please summarize your rebuttal testimony.

A. For a variety of reasons, the export credit rates proposed by Vote Solar and Vivint Solar are not consistent with the costs non-participating customers would otherwise incur in the absence of exports under the proposed Schedule 137. The Company's proposed Export Credit rates are fair for all customers, send efficient price signals that encourage load to be matched with renewable energy output, and are relatively easy to understand.

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission approve the Schedule 137 export credit rates and structure as filed by the Company and require annual updates to ensure avoided costs continue to align with the compensation provided for CG exports.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DJM-1R)
Docket No. 17-035-61
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Daniel J. MacNeil

Historical Export Energy Value

July 2020

PacifiCorp
State of Utah
Historical Export Energy Value Summary by Element

Month	On-Peak Energy $/MWh	On-Peak Losses $/MWh	On-Peak Integration $/MWh	On-Peak Total $/MWh		Off-Peak Energy $/MWh	Off-Peak Losses $/MWh	Off-Peak Integration $/MWh	Off-Peak Total $/MWh	Average* Total $/MWh
10/1/2018	$32.52	$2.59	($0.24)	$34.86		$25.02	$1.96	($0.19)	$26.80	$26.91
11/1/2018	$33.90	$2.67	($0.25)	$36.32		$28.00	$2.17	($0.21)	$29.97	$30.56
12/1/2018	$33.52	$2.78	($0.25)	$36.05		$28.42	$2.31	($0.21)	$30.51	$30.74
1/1/2019	$28.13	$2.38	($0.21)	$30.30		$24.38	$2.00	($0.18)	$26.20	$26.39
2/1/2019	$41.55	$3.40	($0.31)	$44.63		$29.49	$2.31	($0.22)	$31.59	$32.19
3/1/2019	$34.51	$2.67	($0.26)	$36.93		$17.25	$1.29	($0.13)	$18.41	$19.13
4/1/2019	$19.10	$1.42	($0.14)	$20.38		$13.02	$0.94	($0.10)	$13.87	$14.27
5/1/2019	$16.83	$1.27	($0.13)	$17.98		$10.22	$0.80	($0.08)	$10.94	$11.46
6/1/2019	$39.81	$3.79	($0.30)	$43.30		$17.02	$1.49	($0.13)	$18.38	$19.48
7/1/2019	$26.76	$3.06	($0.21)	$29.61		$22.87	$2.38	($0.18)	$25.07	$25.24
8/1/2019	$32.41	$3.47	($0.25)	$35.64		$24.99	$2.46	($0.19)	$27.26	$27.55
9/1/2019	$29.36	$2.71	($0.22)	$31.84		$22.68	$1.93	($0.17)	$24.44	$24.66
Annual*	$28.21	$2.46	($0.21)	$30.46	#	$20.12	$1.71	($0.15)	$21.68	$22.09
Summer*	$33.24	$3.35	($0.25)	**$36.34**	#	$21.57	$2.02	($0.16)	**$23.43**	$23.90
Winter*	$25.59	$2.00	($0.19)	**$27.40**	#	$18.99	$1.47	($0.14)	**$20.32**	$20.70

Definitions:

On-Peak **Summer:** June through September - 4pm - 8pm
Winter: October through May - 7am - 9am & 6pm - 8pm
All Year: Monday - Friday, excluding Holidays

Off-Peak All other, including all day on weekends and holidays

All times are in Mountain Time

* Average values reflect delivery based on historical average export profile

Rocky Mountain Power
Docket No. 17-035-61
Witness: Jacob S. Barker

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Jacob S. Barker

July 2020

Introduction

Q. Please state your name, business address, and present position with PacifiCorp dba Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Jacob S. Barker. My business address is 1407 West North Temple, Salt Lake City, Utah 84116. I am the director of area transmission planning and power quality for Rocky Mountain Power.

Qualifications

Q. Briefly describe your educational and professional background.

A. I have worked for the Company for 18 years in various engineering and management positions. I hold a bachelor's degree in electrical engineering from Utah State University and a master's degree in business administration from the University of Utah.

Purpose of Rebuttal Testimony

Q. What is the purpose of our rebuttal testimony?

A. My rebuttal testimony responds to arguments and recommendations raised by other parties in their direct testimony submitted on March 3, 2020, related to transmission and distribution system capital investment deferral and distribution planning. Specifically, I respond to testimony submitted by the Division of Public Utilities witness Robert A. Davis; Vivint Solar witness Christopher Worley; and Vote Solar witnesses Dr. Carolyn Berry, Curt Volkmann, and Dr. Spencer Yang.

Customer Generation Deferment of Transmission and Distribution

Q. Please describe the parties' proposals to include transmission and distribution capital investment deferral in the export credit.

A. Dr. Berry's testimony describes avoided transmission and distribution capacity investment and cites Dr. Yang's avoided transmission and distribution capacity values of 1.45 cents/kWh and 0.56 cents/kWh respectively.[1] Mr. Worley also describes avoided transmission capacity investment and how he arrived at a value of 1.90 cents/kWh.[2]

Q. Does the Company believe that customer generation can defer transmission and distribution capital investment as proposed by Vivint Solar and Vote Solar?

A. The Company believes that private generation resources may defer capital investment in the short term in its sub-transmission and distribution system in targeted areas but could never eliminate necessary investments to maintain a safe and reliable distribution system.

Q. Why has the Company not included a value for transmission and distribution capital investment deferral?

A. The Company has not included a value for transmission and distribution capital investment deferral because the value is difficult to quantify and may in fact be exceeded by additional costs imposed by customer generation, which are also difficult to quantify. In addition, relying on customer generation to defer capital investment places undue risk on the system.

---

[1] Vote Solar, Affirmative Testimony of Carolyn Berry, lines 476-496.
[2] Vivint Solar, Direct Testimony of Christopher Worley, lines 197-223.

Quantifying Deferral Value

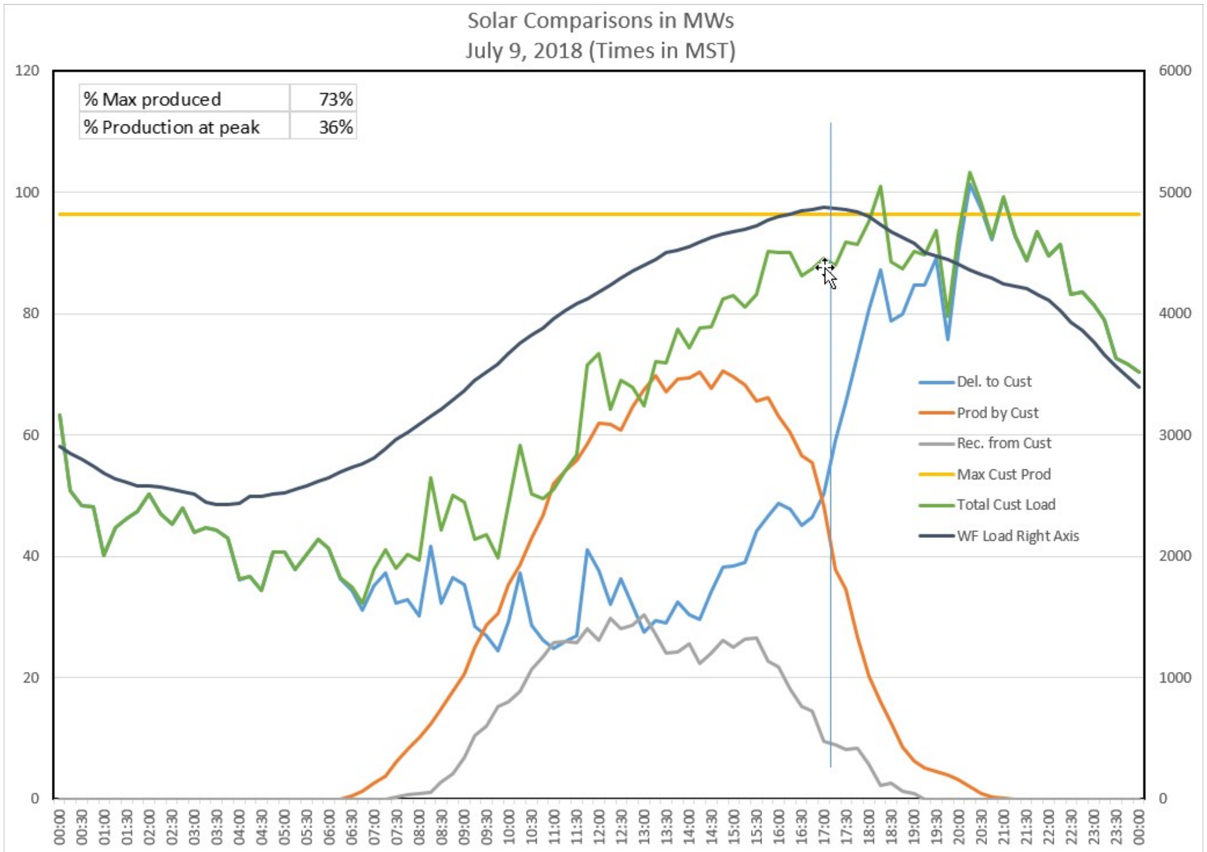
Q. Why is a transmission and distribution capital investment deferral value difficult to quantify?

A. A customer generation interconnection in a no-load growth area will have no impact on the Company's system reinforcement capital investment plan. In areas of the system where capital investments are being made, it may be feasible to defer investment if there is sufficient penetration of customer generation. During the planning phase of a capital investment project, a distributed energy resource screen can determine if a distributed energy resource could reasonably defer the traditional capacity increase solution.

For example, a substation capacity increase project is planned for the 90th South substation in West Jordan, Utah for end of year 2021. The project is justified on a projected area capacity utilization greater than 90 percent, meaning the average peak loading on substations in the area is projected to exceed 90 percent in the summer of 2022. Maintaining area capacity utilization less than 90 percent allows some flexibility within the system for outage restoration, maintenance, and load interconnections. Projected load growth in this area is 2.7 percent (excluding future block commercial loads greater than one megawatt) with a 2019 peak area load of 315 megawatts which equates to 8.5 megawatts of annual growth.

A study of the contribution of private solar generation to the peak was completed for July 9, 2018, which was the summer peak loading day in 2018. This day was deliberately chosen for the study because it was a mostly cloudy afternoon and represented a worst case solar contribution scenario. It was observed that during the peak hour of July 9, 2018, production metered customer solar generation installations along the Wasatch Front contributed 36 percent of their direct current (DC) nameplate capacity to the peak. Figure 1 below illustrates customer loads and onsite generation during this peak day in 2018.

Figure 1. Load and Customer Generation During Peak Day in 2018



Over the last three years, Rocky Mountain Power has connected an average 63.3 megawatts of DC nameplate solar capacity a year, a vast majority of which is on the Wasatch Front. Assuming a homogeneous distribution of customer generation across the Wasatch Front with a peak load in 2019 of 4,921 megawatts related to the 90th South area of 315 megawatts, it is assumed that 4.1 megawatts of customer generation would be connected annually in the 90th South area. Assuming 36 percent nameplate capacity contribution to the peak, the total customer generation offset to the peak in 2019 would have been 1.5 megawatts. In order to defer the 90th South substation project one year, more than five times that quantity would need to be installed to exceed the 8.5 megawatt annual load growth. It should be noted here as well, that although the overall contribution to the peak hour was 36 percent, only 8.5 percent of the nameplate capacity was exported during that same hour. The remainder offsets customers' load.

For the 90th South substation investment, relying on customer generation is not a feasible alternative to the planned expansion of the substation. Furthermore, it demonstrates the difficulty in quantifying the value of capital investment deferral as each capital investment project may or may not be feasible and if feasible would incur a unique value based on how long it could be deferred. To apply a deferral value calculated on overall capital investment projects as the parties' have recommended in their testimony is an oversimplification of the calculation when looked at each capital investment project individually.

Q. What are the risks to the system associated with utilizing private generation to defer capital investment?

A. There is risk associated with being able to bring sufficient customer generation resource on in time to defer a capital project. Capital investment projects from inception to in-service can take anywhere from one to five or more years. The Company does not directly control customer generation installation timeframes, nor does the Company retain a commitment from customer generators to remain in-service. Should a projected customer generation target not be fulfilled over a planned capital investment timeline, the system issue being deferred would be at risk of occurring.

Also, the projected load growth in an area does not include the addition of large block load increases such as a large commercial or industrial customers. Should the Company engage in a targeted customer generation implementation over a period of time to defer an investment, a large new load request could exceed the customer generation target amount. This exceedance may dictate the need for the acceleration of the original capital investment thus voiding the progress made on the customer generation implementation plan.

Customer Generation Effects on the System

Q. How does the variability of customer generation affect the system?

A. Increasing levels of customer generation on the system will cause voltage on the system to vary at a higher rate. This in itself may not cause a system issue; however it will increase the number of mechanical operations infrastructure such as load tap changers, regulators and switched capacitor banks experience. Like any mechanical equipment, increased use will decrease the expected life of the equipment thus increasing replacement costs over the long term. The Company agrees with Mr. Davis' assessment on this matter.[3]

Q. Are there other factors that can increase integration costs?

A. Yes. As noted in Mr. Davis' testimony and consistent with the Company's position, continued installation of customer generation throughout the system and in particular high penetration areas may cause steady-state voltage issues. The solution to this issue

[3] Division of Public Utilities, Direct Testimony of Robert A. Davis, lines 329-374.

would be the addition of voltage regulating devices. Since Level 1 engineering application reviews do not take voltage variability into account, as voltage issues manifest, the Company would incur those costs.

In addition, as customer generation increases on the system, protection and control infrastructure will be required. While this equipment is typically funded by the interconnection customer initially, future system changes such as a circuit reconfiguration can modify the protection and control such that new infrastructure is required for the reconfiguration. This new infrastructure would be funded by the Company with recovery from all customers.

The Company disagrees with Mr. Volkmann's methodology of utilizing past years' integration costs[4] to evaluate future integration costs as the aforementioned voltage and protection and control scenarios are related to higher customer generation penetration levels.

Distribution Planning

Q. Does the Company agree with Mr. Volkmann's recommendation to consider implementing integrated distribution planning?

A. Not at this time. The Company has already implemented additional study practices within its distribution planning process to accommodate increases in customer generation and to assess circuit hosting capacity. The substation metering project completed as part of the Sustainable Transportation and Energy Plan has also added valuable data-based insight in areas of the system where hosting capacities and voltage profiles were previously based on modeling and engineering experience. Because of

[4] Vote Solar, Affirmative Testimony of Curt Volkmann, lines 319-323.

the benefits of these distribution planning improvements, the Company does not believe integrated distribution planning would provide sufficient benefit over current distribution planning processes to offset the cost of implementation.

Conclusion

Q. Can you summarize your testimony?

A. Yes. Because it is difficult to predict and quantify the potential for capital investment deferral and the costs associated with increased solar penetration, it is not appropriate to include deferral value in the export credit at this time.

Rocky Mountain Power
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Robert M. Meredith

July 2020

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

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. I respond to the direct testimonies of Division of Public Utilities ("DPU") witness Mr. Robert A. Davis, Office of Consumer Services ("OCS") witness Ms. Cheryl Murray, Utah Clean Energy ("UCE") witness Ms. Kate Bowman, Vote Solar witness Mr. Sachu Constantine, and Vivint Solar witness Christopher Worley and support the Company's proposed program design for Schedule 137 – Net Billing Service. I also propose a modification to Schedule 137, which would make batteries be one of the customer-sited technologies that would qualify a customer for service under this tariff schedule.

Response to DPU Witness Mr. Davis

Q. In Mr. Davis' direct testimony, he recommends that it would be preferable for the seasonal definition used for pricing export credits to match the seasonal definitions used for different summer and winter retail rates.[1] Do you agree?

A. Yes. The Company agrees that it makes sense for the seasonal definitions used to value export credits in the Net Billing program and those listed on retail tariffs be in alignment. In its general rate case filing in Docket No. 20-035-04 ("2020 GRC"), the Company proposes to move May from the higher cost summer season to the lower cost winter season. The Company is proposing this change in both proceedings, because

[1] *See* lines 477 through 488 of DPU witness Mr. Robert A. Davis' Direct Testimony.

making May a lower cost month better reflects the underlying economics of energy value. Since both this export credit proceeding and the 2020 GRC have target effective dates of January 1, 2021, the seasons will be in alignment for each filing as recommended by the DPU, if approved by the Commission.

Response to OCS Witness Ms. Murray

Q. In testimony, Ms. Murray expressed concerns about the simplicity and transparency of the Company's proposed Net Billing program.[2] Please comment.

A. In discovery, the Company responded to these concerns with an example showing how Net Billing would work relative to the existing Transition Program for Customer Generators ("Schedule 136"). The Company's response to data request OCS 4.1, provided as Exhibit RMP___(RMM-1R), shows an example of how the calculation of delivered and exported energy using 15 minute netting in Schedule 136 compares to what the Company proposes for Net Billing. Net Billing simply considers all the energy sent to the grid as exports and all energy sent from the grid to the customer as deliveries. In contrast, under existing Schedule 136, the energy delivered from the utility to the customer is compared to the energy the customer exports to the grid in each 15 minute interval period and netted. Net Billing would not rely on any interval and would not net any energy like Schedule 136. It is therefore easier to understand than Schedule 136.

Q. Ms. Murray also expressed concern that the proposed program name of "Net Billing" could be confusing to customers.[3] Why did the Company use this name?

A. As different utilities across the country have adopted successor programs to their Net Energy Metering programs, the term "Net Billing" has become an industry term that

[2] *See* lines 96 through 113 of OCS witness Ms. Cheryl Murray's Direct Testimony.
[3] *See* lines 105 and 106 of OCS witness Ms. Cheryl Murray's Direct Testimony.

means a customer generator program where participants can offset retail electric charges for what they use of their generation onsite and get compensated at a different cost-based rate for energy they export to the grid.[4] Net Billing differs from Net Energy Metering because instead of offsetting the quantity of energy billed, the bill itself is offset by financial credits.

Q. Have any other utilities used the term "Net Billing" as a name for their customer generation program?

A. Yes. Imperial Irrigation District,[5] Broad River Electric Cooperative,[6] City of Westminster,[7] and Bartholomew County Rural Electric Membership Corporation[8] all have Net Billing programs. In California, the Company also has a Net Billing tariff in effect for all new customer generators that the Company serves in that jurisdiction.[9]

Q. Ms. Murray identified a reference in the Company's proposed Schedule 137 tariff where the "Transition Program Service" was referenced and recommended changing the reference to "Net Billing Service".[10] Do you agree with her recommendation?

A. Yes.

[4] *See* https://www.lawinsider.com/dictionary/net-billing and https://www.nrel.gov/docs/fy18osti/68469.pdf.
[5] *See* https://www.iid.com/energy/rooftop-solar/interconnection/net-billing.
[6] *See* https://www.broadriverelectric.com/energy-solutions/renewable-energy/net-billing-policy/.
[7] *See* http://www.westminstersc.org/net-billing.
[8] *See* https://www.bcremc.com/about-us/rates/net-billing-rate-schedule/.
[9] *See* https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/rates/NB-136_Net_Billing_Service.pdf.
[10] *See* lines 114 through 122 of OCS witness Ms. Cheryl Murray's Direct Testimony.

Response to UCE Witness Ms. Bowman

Q. Ms. Bowman discusses the benefits of distributed energy resources ("DER") and how they can improve grid flexibility and should be a key consideration in determination of an export credit rate.[11] Please summarize your understanding of her perspective.

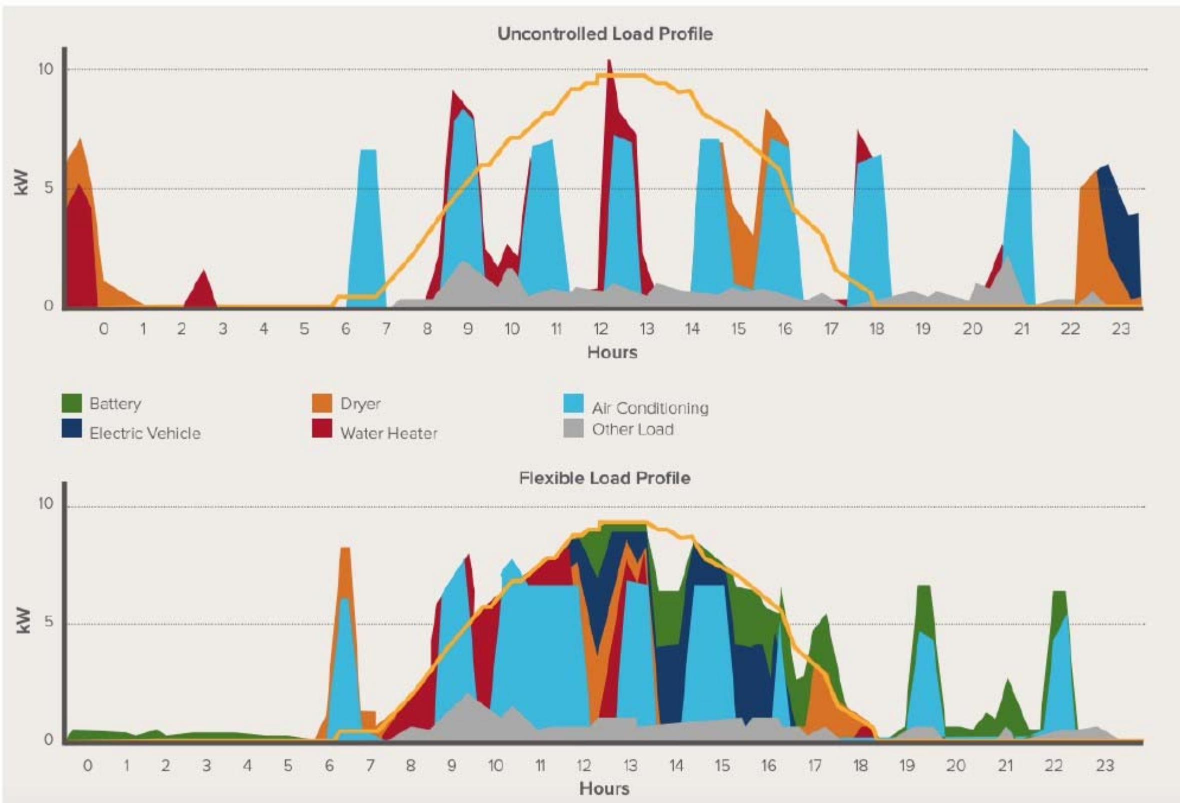
A. Ms. Bowman explains that DERs, which along with rooftop solar include such things as customer-sited batteries, electric vehicle charging, and building control technologies, can help the Company develop greater flexibility in matching supply with demand and can provide other services. She then discusses how other DERs can be complementary to rooftop solar and enhance its benefits. Finally she reasons that keeping rooftop solar economically viable for customers is important, because when customers adopt onsite solar technology, they become more engaged and thus more likely to adopt other DERs and innovative programs.

Q. Do you agree with her that statement that while "the future potential of DER may not be immediately quantifiable, the benefits of improved grid flexibility resulting from private investments in DER should be a consideration in the determination of the Export Credit Rate"?[12]

A. I agree with her that the future potential of DERs is not quantifiable. I also agree that the export credit program should be structured in light of the DER technologies now available. Now more than ever before, a variety of consumer technologies that can provide benefits to the grid are becoming widely available. The rise of the Internet of Things ("IoT") technologies has begun pervading traditional behind-the-meter

[11] *See* lines 67 through 188 of UCE witness Ms. Kate Bowman's Direct Testimony.
[12] *See* lines 48 through 51 of UCE witness Ms. Kate Bowman's Direct Testimony.

household equipment such as water heaters, thermostats and lighting. At the same time, electric vehicles and onsite batteries are emerging as new opportunities for greater grid flexibility. Ms. Bowman shares in her testimony the following charts below[13], which come from a Rocky Mountain Institute report on demand flexibility:



These charts illustrate how customer load can be controlled to much more closely align consumption with solar generation output. Using smart controls, the loads from electric vehicle charging, water heating, air conditioning, clothes drying, and battery re-charging can be timed to optimize the use of onsite solar power. Instead of sending more energy onto the grid often at times when its value is low and the system is flooded from energy from other customer generators and utility scale solar, including solar

[13] *See* Figure 1 in UCE witness Ms. Kate Bowman's Direct Testimony.

exported to the Company from California, such an alignment shifts load away from critical higher cost times. In essence, the value of customer-sited renewable generation is greater when load is more closely aligned with its output—something that the Company's proposed Net Billing program would send a strong price signal to encourage.

Q. How will the Company's proposed Net Billing program encourage alignment of load with renewable output and thus help to foster DER adoption and innovation?

A. Under Net Billing as proposed by the Company, participants will be compensated when they export energy to the grid at a price that is on average about 1.5 cents per kilowatt-hour ("kWh").[14] However, when their loads occur at the same time as their generation, they will instead reduce their billed energy and save at the retail energy rate, which at current levels varies between about 8.8 cents per kWh and 14.5 kWh for residential customers[15] depending on season and overall monthly household consumption. The Company anticipates that this difference in cost will spur customers, entrepreneurs, and solar installers to find innovative solutions like those illustrated in the charts Rocky Mountain Institute presents to better match onsite solar generation with load. Under traditional net metering or even the existing Schedule 136 program, this same incentive does not exist, and customer generators have very little incentive to purchase and make use of an onsite battery or shift loads to lower cost high renewable times.

[14] *See* Exhibit RMP___(DJM-1).
[15] *See* the Company's Utah Electric Service Schedule No. 1.

Q. Ms. Bowman recommends that the export credit rate should not be netted more frequently than on an hourly basis.[16] What are her reasons for this recommendation?

A. Her reasons for an hourly interval for netting include that it is easier to understand than netting over shorter intervals and better aligns with the time increments on other rate schedules which have on- and off-peak hours that are based upon discrete hourly times.

Q. Do you think an hourly interval is easier for customers to understand than the Company's proposal which has no netting?

A. No. Netting over intervals periods like the 15-minute netting that occurs on the existing Schedule 136 program is inherently more complex than simply not netting and measuring all exported energy and all delivered energy, as the Company proposes for the Net Billing program.

Q. Since time of use schedules have on- and off-peak periods that begin and end with discrete hourly periods, is that a good reason why exports should be netted under hourly intervals period?

A. No. The interval by which exports are netted for a customer generation program is not related to and should not be conflated with periods of time when energy is considered on-peak or off-peak. The two are concepts are fundamentally different.

Q. Why is the Net Billing program proposed by the Company with no interval netting a better program design than netting hourly or over some other interval?

A. As discussed in my direct testimony, no netting better reflects the intertemporal reality of the service the Company provides, is a simpler concept to explain to customers, and

[16] *See* lines 281 through 292 of UCE witness Ms. Kate Bowman's Direct Testimony.

it is less administratively burdensome for the Company.[17] Further, when considering the new technologies available to customers that were discussed earlier in this testimony, it is important to consider that the experience of seeking to match load with onsite generation on an instantaneous basis will be likely a seamless one from the customer's perspective for customers who adopt innovative technologies for this program. For example, if a customer installs a battery, it would be programmed to reduce exports and serve the customer's load with stored solar energy in a way the customer would not notice. There is therefore little reason why the goal of adopting such technology shouldn't be to match load with renewable output as accurately as possible. Using an hourly or 15 minute interval sets the bar lower than is necessary and does not make sense in light of the technology that will likely be adopted to respond to the price signals of Net Billing.

Q. Does it make sense to prop up the small-scale solar installation industry with artificially high export rates, so that more DERs might be adopted?

A. No. Setting both the price of exported energy at its value and charging customers for the energy they take from the Company at its cost of service will be fair for all customers and will simultaneously drive far more customer investment in other DER technologies, as participants seek out ways to match their loads with solar output.

Response to Vote Solar Witness Mr. Constantine

Q. Mr. Constantine also supports netting over an hourly interval period. What reasons does he give?

A. Mr. Constantine gives two reasons for hourly netting: 1) it is more understandable than

[17] *See* lines 106 through 143.

15-minute netting; 2) it is more actionable than 15-minute netting.[18]

Q. Is the Company's proposed Net Billing program, where there would be no netting, less understandable than netting over 15 minute or hour periods?

A. No. While I agree with Mr. Constantine that it can be challenging to estimate how energy consumption lines up with solar output, he provides no reason why it would be less challenging to do so under hourly netting periods than it would under a program with no netting. Also, as I discussed earlier in my testimony, no netting is easier for customers to understand.

Q. Is netting over a longer period inherently more actionable?

A. No. The 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.

---

[18] *See* lines 386 through 423 of Vote Solar witness Mr. Sachu Constantine's Direct Testimony.

Q. In support of hourly netting, Mr. Constantine asserts that "(r)esidential customers in particular will have little understanding or control over their intra-hour electric consumption habits as many drivers of residential consumption like air conditioners, refrigerators, and other major appliances cycle on and off automatically. For those load drivers that are controlled by the customer such as dishwashers, washing machines, hair dryers, and other appliances, many residential customers will find it difficult to adjust consumption within the hour, as family schedules and work schedules drive meal times and appliance use, rather than the desire to match load with solar consumption."[19] Please comment.

A. I agree that customers may have difficulty adjusting some portion of their load within a given hour to match solar production. However, appropriate price signals will encourage customers to use technology to automate and control their load to coincide with solar output. There is no good reason to support the idea that netting over an hour or 15 minute period would elicit a better response from customers than no netting.

Response to Vote Solar Witness Mr. Christopher Worley

Q. Why does Mr. Worley recommend hourly netting?

A. Mr. Worley gives some of the same reasons for hourly netting as other witnesses to which I have responded. He asserts that "(r)esidential customers cannot be reasonably expected to respond to changes in their solar system production on a 15-minute basis." [20] He also states that "(r)esidential solar customers are not independent power

[19] *See* lines 407 through 414 of Vote Solar witness Mr. Sachu Constantine's Direct Testimony.
[20] *See* lines 261 through 263 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony.

producers"[21]and reasons that "they should not be expected to manage their net energy consumption on a 15-minute basis."[22]

Q. Does Mr. Worley present any compelling reasons why hourly netting is preferable to the Company's proposed program which would not net energy?

A. No. As I discussed previously, technology will likely enable customers to respond just as well to no netting as they would be able to under hourly netting. While I agree with him that customer generators are not independent power producers, I think that is all the more reason why program participants should be encouraged to generate power for their own energy needs. The proposed Net Billing program achieves this by accurately delineating exported energy and delivered energy and not confusing the measurement of both within specific interval periods.

Change to Proposed Schedule 137 Tariff

Q. Does the Company have any changes to its proposed Schedule 136 - Net Billing tariff?

A. Yes. The Company proposes that batteries be listed as a technology that would make a customer eligible for taking service under Net Billing.

Q. Why does the Company want to add batteries as a technology that would qualify a customer for service under Schedule 137?

A. Schedule 137 lays out parameters for safely interconnecting customers able to export energy to the grid. At present, however, batteries alone do not qualify a customer to take service under customer generation programs. For a customer with a battery to interconnect to the grid, a customer must go through a more rigorous process than

---

[21] *See* line 263 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony.
[22] *See* lines 266 through 267 of Vivint Solar witness Mr. Christopher Worley's Direct Testimony.

that which is laid out in Schedule 137. Making the proposed change will make the interconnection process simpler for customers who want to interconnect onsite batteries.

Q. If a much higher export credit price than that which is proposed by the Company were approved, what provision should be in the tariff to protect non-participating customers from customer-sited battery resources?

A. If the Commission approves a much higher export credit price, the price should be capped at the retail rates for each schedule to prevent customers from pursuing the uneconomic arbitrage opportunity that they could take advantage of with an exporting battery system.

Conclusion

Q. Please summarize your rebuttal testimony.

A. The Company's proposed Net Billing program is fair for all customers, sends efficient price signals that encourage load to be matched with renewable energy output, and is relatively easy to understand.

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission approve the Company's proposed Schedule 137 tariff.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RMM-1R)
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

OCS Data Request 4.1

July 2020

17-035-61 / Rocky Mountain Power
March 11, 2020
OCS Data Request 4.1

OCS Data Request 4.1

Regarding Mr. Meredith's direct testimony beginning at line 47 concerning Schedule 136:

(a) Provide a numerical example and explain exactly how the meters have worked for customers who have been on Schedule 136, in which exported and delivered energy have been netted on a 15 minute interval basis.

(b) Provide detailed specifications of the primary meters that have been used for these customers.

Response to OCS Data Request 4.1

(a) Please refer to Attachment OCS 4.1 which provides a numerical example of how both 15-minute interval netting, as has been done on Schedule 136, and no interval netting, as has been done on Schedule 135 and as is proposed for Schedule 137, work. Under 15-minute interval metering, delivered energy and exported energy are compared and if delivered exceeds exported, then that net quantity of delivered energy is used. Conversely, if exported exceeds delivered, then that net quantity of exported energy is used. In no interval period will both delivered and exported energy both be used simultaneously for the same interval. With no interval netting, the total quantity exported is used and the total quantity of delivered is used.

(b) The meter used for residential and small commercial Schedule 136 installations is a bi-directional, form 2S, three wire, 240 volts alternating current (VAC) electronic meter with mass memory to store interval data and an optical port to manually retrieve the interval data.

Rocky Mountain Power
Exhibit RMP___(RMM-1R) Page 2 of 2
Docket No. 17-035-61
Witness: Robert M. Meredith

Illustrative Example of 15 Minute Interval Netting Compared to No Netting

Time (15 minute period beginning)	Register Measuring Energy Delivered to Customer from RMP (kW)	Register Measuring Energy Supplied from Customer to RMP (kW)	Energy Delivered to Customer from RMP with 15 Minute Interval Netting (Done on Schedule 136)	Energy Supplied from Customer to RMP with 15 Minute Interval Netting (Done on Schedule 136)
10:00 AM	1	2	0	1
10:15 AM	0	2	0	2
10:30 AM	2	2	0	0
10:45 AM	1	3	0	2
11:00 AM	0	4	0	4
11:15 AM	0	4	0	4
11:30 AM	1	4	0	3
11:45 AM	1	4	0	3
12:00 PM	1	4	0	3
12:15 PM	1	4	0	3
12:30 PM	0	5	0	5
12:45 PM	0	6	0	6
1:00 PM	4	5	0	1
1:15 PM	2	4	0	2
1:30 PM	3	1	2	0
1:45 PM	1	4	0	3
nergy (kWh = Sum / 4 for 15 minute	4.5	14.5	0.5	10.5
	Measurements used in billing for Schedule 135 and Proposed Schedule 137 (No Interval Netting)		Measurements used in billing for Schedule 136 (15 Minute Interval Netting)	

CERTIFICATE OF SERVICE

I hereby certify that on July 15, 2020, a true and correct copy of Rocky Mountain Power's **REBUTTAL TESTIMONY** in Docket No. 17-035-61 was served by email on the following Parties:

Division of Public Utilities	
Chris Parker **(C)** William Powell **(C)**	ChrisParker@utah.gov wpowell@utah.gov
Utah Office of Consumer Services	
Michele Beck **(C)** Cheryl Murray **(C)** Bela Vastag **(C)**	mbeck@utah.gov cmurray@utah.gov bvastag@utah.gov
Assistant Utah Attorney General	
Patricia Schmid **(C)** Justin Jetter **(C)** Robert Moore **(C)** Victor Copeland **(C)**	pschmid@agutah.gov jjetter@agutah.gov rmoore@agutah.gov vcopeland@agutah.gov
Vivint Solar	
Stephen F. Mecham **(C)**	sfmecham@gmail.com
Vote Solar	
Sachu Constantine **(C)** Claudine Custodio **(C)** Jennifer Selendy **(C)** Joshua S. Margolin **(C)** Philippe Z. Selendy **(C)** Margaret M. Siller	sachu@votesolar.org claudine@votesolar.org jselendy@selendygay.com jmargolin@selendygay.com pselendy@selendygay.com msiller@selendygay.com
Utah Clean Energy	
Sarah Wright **(C)** Kate Bowman **(C)** Hunter Holman **(C)**	sarah@utahcleanenergy.org kate@utahcleanenergy.org hunter@utahcleanenergy.org
Utah Solar Energy Association	
Ryan Evans **(C)**	revans@utsolar.org
Salt Lake City Corporation	
Megan J. DePaulis Christopher Thomas **(C)**	megan.depaulis@slcgov.com christopher.thomas@slcgov.com

Auric Solar, LLC	
Elias Bishop	elias.bishop@auricsolar.com
Western Resource Advocates	
Sophie Hayes **(C)** Nancy Kelly **(C)** Steven S. Michel **(C)**	sophie.hayes@westernresources.org nkelly@westernresources.org smichel@westernresources.org
Healthy Environment Alliance of Utah	
Noah Miterko	noah@healutah.org
Rocky Mountain Power	
Data Request Response Center Emily Wegener Jana Saba	datarequest@pacificorp.com emily.wegener@pacificorp.com jana.saba@pacificorp.com; utahdockets@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations