ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

February 22, 2021

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**

Pursuant to the Scheduling Order and Notice of Hearing issued January 20, 2021 in the above referenced docket, Rocky Mountain Power (the "Company") hereby submits for filing its sur-surrebuttal testimony addressing the Limited Rehearing Issues.

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

CERTIFICATE OF SERVICE

I hereby certify that on February 22, 2021, a true and correct copy of Rocky Mountain Power's **Sur-surrebuttal 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	
Alyson Anderson Bela Vastag **(C)** Alex Ware	akanderson@utah.gov bvastag@utah.gov aware@utah.gov ocs@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)** Shelby Rokito Spencer Gottlieb	sachu@votesolar.org claudine@votesolar.org jselendy@selendygay.com jmargolin@selendygay.com pselendy@selendygay.com srokito@selendygay.com sgottlieb@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)** April Elliott	sophie.hayes@westernresources.org nkelly@westernresources.org april.elliott@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

Mary Penfield
Adviser, Regulatory Operations

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

Sur-surrebuttal Testimony of Daniel J. MacNeil

February 2021

Q. Are you the same Daniel J. MacNeil that presented direct, rebuttal, and sur-rebuttal testimony in this proceeding?

A. Yes.

Purpose of Sur-Surrebuttal Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. I provide testimony related to the carrying charge and capacity contribution values that should be applied to avoided generation, transmission, and distribution capacity costs, as identified in the Utah Public Service Commission ("Commission's") December 23, 2020 Order on Agency Review or Rehearing.

Q. Please provide a summary of your sur-surrebuttal testimony.

A. The Commission's October 30, 2020 Order ("October Order") stated that it adopted the capacity contribution value proposed by Vote Solar ("VS") witness Dr. Michael Milligan because it included only resources currently operating and rejected my proposal because it included planned future resources.[1] However, Dr. Milligan's capacity contribution does not account for any utility-scale solar resources, despite the significant and growing presence of such resources within Utah, and Dr. Milligan's admission that solar capacity contribution declines with increasing solar penetration.[2] In addition, my rebuttal testimony provided a variety of generation capacity contribution alternatives which, unlike Dr. Milligan's proposal, account for the impact of weather on load and customer generation ("CG") exports and do not include planned future resources. In light of the Commission's decision to adopt annual updates to the export credit rate, I have prepared a generation capacity contribution value that is specific to the utility-scale

[1] *Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity*, Docket No. 17-035-61, Order at 15 (Oct. 30, 2020) ("October Order").
[2] See Oct. 2, 2020 Hearing Transcript pg. 809

solar resources committed to be online in the 2021 rate-effective period. This value is slightly higher than my rebuttal recommendation. Table 2 in my testimony provides a detailed comparison of the results and assumptions underlying the variety of generation capacity contribution values identified by Dr. Milligan and myself.

The October Order adopted the same capacity contribution values for generation, transmission, and distribution; however, the need for generation, transmission, and distribution upgrades is not necessarily driven by the same conditions, and these investments are also subject to different cost allocation. In particular, VS has proposed transmission costs based on PacifiCorp ("RMP" or "the Company's") Open Access Transmission Tariff ("OATT") rates. The Company generally serves retail customers in Utah using Network Integration Transmission Service ("NITS") provided by PacifiCorp Transmission. Under the OATT, the cost of NITS is based on a transmission customer's hourly load coincident with PacifiCorp Transmission's Monthly Transmission System Peak.[3] In five months of 2019 (mainly in the winter), the VS CG export profile was zero during the Monthly Transmission System Peak, and thus would not contribute to cost savings for other Utah customers, significantly reducing its effective capacity contribution. As a result, using the Monthly Transmission System Peak instead of the top 10 percent of Utah load hours proposed by VS more accurately reflects the avoided transmission capacity costs resulting from CG exports.

Utah distribution-system costs are allocated entirely to Utah customers, so the transmission allocation is not applicable. In addition, utility-scale generation resources

[3] See PacifiCorp Open Access Transmission Tariff. Section 34. (Updated January 8, 2021). Available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20210108_OATTMASTER.PDF (accessed 2/19/2021)

are typically delivered to retail customers across the distribution system, so unlike generation capacity contribution it is not appropriate to net them out of the Utah load when considering the highest load hours that are likely to drive the need for distribution system upgrades. My rebuttal testimony included scenarios incorporating these parameters that would be reasonable for determining distribution capacity contribution.

The Commission's adjustment to the generation carrying charge was not appropriate because Dr. Milligan's sur-rebuttal generation capacity cost value already reflected the carrying cost for a simple cycle combustion turbine ("SCCT") from the Company's 2019 Integrated Resource Plan ("IRP"). Similarly, the Commission's adjustment to the transmission carrying charge was not appropriate because Dr. Spencer Yang's proposed transmission cost already represented an annual revenue requirement, and not a capital cost. While the distribution carrying charge proposed by VS is not appropriate for use in this proceeding, the carrying charge identified by the Commission is specific to the twenty-year life of a SCCT, which is shorter than the Company's assumed life for distribution investments. The Company proposes that CG export credit reflect the same carrying charge used to calculate distribution deferral credits for energy efficiency resources in the Company's 2019 IRP.

To better illustrate the calculations used to convert capacity costs to export credits, I have presented the VS proposals underlying the Commission-ordered rates, the Commission-ordered adjustments, and my recommended export credit values in Table 3 (Generation Capacity Credit), Table 4 (Transmission Capacity Credit), and Table 5 (Distribution Capacity Credit).

Q. What are your recommendations?

A. I recommend that the Commission approve a capacity credit for CG exports totaling 1.13 cents/kilowatt-hour ("kWh"), as summarized in Table 1 below.

Table 1: Total CG Export Capacity Credits (2021$)

Type	Capacity Contribution (before losses) (%)	Carrying Charge (%)	Credit (cents/kWh)
Generation Capacity Credit	6.49%	6.96%	0.62
Transmission Capacity Credit	7.72%	n/a	0.31
Distribution Capacity Credit	21.99%	6.51%	0.21
Total			1.13

Generation Capacity Contribution

Q. What generation capacity contribution did the Commission approve in its October Order?

A. The October Order states that the Commission approves the capacity contribution value proposed by VS and applies that same value to the avoided generation, transmission, and distribution capacity costs.[4] While the October Order did not explicitly identify the capacity contribution that was approved, it does identify the resulting avoided capacity costs from which the underlying capacity contribution can be identified.

The Commission's avoided generation capacity cost value of 2.31 cents/kWh represents a reduction of 16.7 percent from the value of 2.77/kWh cents included in the sur-rebuttal workpapers of VS witness Dr. Milligan. This 16.7 percent discount represents the difference between the 9.39 percent annual carrying charge proposed by Vivint Solar and VS in direct testimony and the 7.82 percent annual carrying charge

[4] October Order at 15.

from PacifiCorp's 2020 general rate case in Utah, Docket No. 20-035-04. Dr. Milligan's sur-rebuttal workpapers demonstrate that the 2021 value of 2.77 cents/kWh is actually derived from a capacity contribution of 28.96 percent.[5]

Q. Did Dr. Milligan identify the basis for the revision from the 27.65 percent capacity contribution he initially proposed to the 28.96 percent used in his sur-rebuttal?

A. Yes. Dr. Milligan's sur-rebuttal testimony stated that he recalculated his proposed capacity contribution after controlling for the day of the week, resulting in a higher capacity contribution.

Q. Why was controlling for the day of the week necessary?

A. The VS CG export profile is based on 2019 actual data, while Dr. Milligan's original capacity contribution calculation is based on PacifiCorp's forecasted hourly Utah loads starting in 2021. January 1st occurs on a different day from year to year, and weekends and holidays also occur on different days from year to year. Adjusting the 2019 export profile to match the days of the week in the forecasted load preserves the relationship between expected load and expected exports on weekdays and weekends.

Q. Is controlling for day of the week sufficient to produce a reasonable forecast of the customer exports during peak load conditions?

A. No. As I noted in my rebuttal testimony, Dr. Milligan's original capacity contribution calculation does not account for differences in weather between the historical export credit profile and the load forecast.

Q. Does Dr. Milligan agree that weather impacts both load and solar generation?

[5] See tab "NPV Capacity", cells C17 and C7 of VS witness Dr. Milligan's sur-rebuttal workpaper "CONFIDENTIAL 17-035-61 Phase 2 VS Workpapers MM – 2 9-15-2020 Milligan2.xlsx"

A. Yes.[6]

Q. Did Dr. Milligan make an adjustment to account for the impact of weather?

A. No. He instead indicates that weather is accounted for implicitly.[7]

Q. Does Dr. Milligan's proposed capacity contribution reasonably account for weather?

A. No. The Utah system peak load occurred on July 22 in 2019, while the Utah system peak load in the Company's 2021 load forecast occurs on July 14th. Under Dr. Milligan's original proposal, exports on July 14, 2019 were compared against the 2021 load forecast on July 14, 2021. Under Dr. Milligan's revised proposal in his sur-rebuttal testimony, exports on Wednesday, July 17, 2019 were compared against the 2021 load forecast for Wednesday, July 14, 2021. July 17, 2019 had the 10th highest daily average Utah load in July 2019, so comparing it to the highest forecast load in 2021 is inappropriate, as the two represent different weather conditions. The daily average CG exports on July 17, 2019 were 19 percent higher than on the peak load day of July 22, 2019, which contributes to an overstated capacity contribution when it is compared to the peak load day in the 2021 load forecast.

Q. Were there any other differences between Dr. Milligan's initial and sur-rebuttal capacity contribution proposals?

A. Yes. The capacity contribution value reported in Dr. Milligan's direct testimony was not grossed up for line losses. Dr. Milligan's sur-rebuttal grossed up the capacity payment to account for line losses even though the capacity contribution value is based

---

[6] *See* line 625 of VS witness Dr. Michael Milligan's Sur-rebuttal Testimony.
[7] *See* line 626-627 of VS witness Dr. Michael Milligan's Sur-rebuttal Testimony.

on an export credit profile that has already been grossed up for line losses, which resulted in a double count of avoided line losses.

Q. Does weather impact more than just the system peak load day?

A. Yes. It impacts both load and CG exports on every day of each month.

Q. If a day of historical exports was lined up with the day of equivalent rank in the load forecast, would that ensure that equivalent weather was represented in both data sets?

A. Not necessarily. The Company's load forecast consists of normalized data with the intent that the forecasted value is equally likely to be higher or lower than actual load. This same treatment applies to the 2nd highest load day, 3rd highest load day, and so on. In contrast, the 2019 actuals reflect a particular sample of conditions which may be above or below the long-term average. The weather in 2019 may not be representative of normal conditions that are forecasted to occur in 2021 and it would be difficult to transform 2019 customer exports into a normalized forecast for 2021.

Q. Is there a data set available in which the weather and day of week for customer exports and Utah load are aligned?

A. Yes. My rebuttal testimony provided several data points using the VS CG export profile, derived from 2019 actuals, and the Company's hourly actual Utah loads for 2019. Because these two data sets reflect the same historical period, they automatically reflect the same weather and day of the week.

Q. Can you please provide a summary of generation capacity contribution values discussed thus far in this docket?

A. Yes. Table 2 identifies the generation capacity contribution values identified by Dr. Milligan and myself, as well as the underlying assumptions for each value.

Table 2: Generation Capacity Contribution Comparison

Version	Time Period	Cap. Contrib.	Cap. Contrib. w/ Losses	Customer Gen. resources included	Utility-Scale resources included	Load	Match day of week?	Match Weather?
VS CG Export Profile based on 2019 actual data is used in all scenarios.								
VS Scenarios:								
Milligan Dir.	2021-40	27.65%		Forecast	None	Forecast UT	No	No
Milligan Dir.	2021	27.49%		Forecast	None	Forecast UT	No	No
Milligan SR	2021-40		29.50%	Forecast	None	Forecast UT	Yes	No
Milligan SR	2021		28.96%	Forecast	None	Forecast UT	Yes	No
RMP Rebuttal Scenarios:								
2019 Utah Load	2019	21.99%	24.18%	Actual	None	Actual UT	Yes	Yes
2019 System Load	2019	18.81%	20.70%	Actual	None	Actual System	Yes	Yes
2019 Utah Load Net of 2019 Utah Solar	2019	11.83%	13.04%	Actual	Operating	Actual UT	Yes	Yes
2019 Utah Load Net of Contracted Utah Solar	2019	4.14%	4.58%	Actual	Operating, Contracted	Actual UT	Yes	Yes
2019 IRP Forecast	2030	3.73%	4.12%	Forecast	Operating, Contracted, Projected in 2030	Forecast System	No	No
RMP Sur-surrebuttal Scenario:								
2019 Utah Load Net of 2021 Utah Solar	2019	6.49%	7.16%	Actual	Operating, COD before summer 2021	Actual UT	Yes	Yes

Q. Are the capacity contributions identified in Table 2 developed using a comparable methodology?

A. For the most part, yes. All of the scenarios except the 2019 IRP Forecast listed in Table 2 rely upon the average VS export profile during the top 10 percent load or net load hours. Dr. Milligan proposed this methodology in his direct testimony and deemed the top 10 percent as the appropriate metric for emulating the results of a more comprehensive capacity contribution calculation. While 10 percent may or may not be the appropriate cut-off, benchmarking using a more comprehensive capacity contribution calculation would be necessary to discern the appropriate result and it would have limited broad applicability as the results would be impacted by changes in the patterns of the Company's loads and its resource mix. I instead proposed alternate inputs to Dr. Milligan's calculation to more closely align with the VS export profile and PacifiCorp's generation resource requirements.

Q. Which VS and RMP capacity contribution calculations are most comparable?

A. Dr. Milligan's sur-rebuttal capacity contribution for 2021 is most comparable to my "2019 Utah Load" scenario. The difference is that Dr. Milligan uses the top 10 percent of forecasted Utah load for 2021, whereas my "2019 Utah Load" scenario uses the top 10 percent of actual Utah load in 2019.

Q. What is the key difference between these two proposals?

A. Dr. Milligan's calculation compares an export credit profile based on the actual weather in 2019 to a Utah load forecast that reflects normalized weather. This results in a random alignment between the historical weather in the export credit profile and the normalized weather in the load forecast. In contrast, my calculation compares the same export credit profile based on the weather in 2019 to the Utah load profile in 2019.

Because Dr. Milligan's calculation fails to realistically account for the effect of weather, it results in an overstated capacity contribution.

Q. Please explain the differences in your other scenarios that are based on 2019 actuals.

A. Utah customers are allocated a share of all of the resources the Company procures to serve its entire six state system, rather than solely resources within the state of Utah. Because the Company's western states have relatively higher winter loads when CG exports are lower, switching from 2019 Utah load actuals to 2019 system-wide load actuals results in a lower capacity contribution.

In 2019 Utah customers were already paying for a large number of solar resources within the state of Utah that were online and operating. Because Utah customers are already receiving the benefits of the output from these resources, the risk of loss of load events is significantly reduced during daylight hours from what it would otherwise be. The scenario "2019 Utah Load Net of 2019 Utah Solar" takes 2019 hourly actual Utah load and subtracts from it the 2019 hourly actual generation from utility-scale solar resources in Utah. When utility-scale solar generation is netted out, a number of daytime hours are no longer in the top 10 percent and are instead replaced within evening hours when CG exports are reduced, resulting in a lower capacity contribution.

Utah customers are already committed to pay for additional solar resources within the state of Utah that weren't online in 2019. To accurately set export credit rates, it is appropriate to take into account resources that will be online during the rate effective period, in addition to those that were already online and reflected in the historical data in the previous scenario. At the time of my rebuttal testimony, I identified that contracts had been executed for just under 700 megawatts ("MW") of additional solar resources in Utah. Since my rebuttal testimony was prepared, RMP has entered contracts for an additional 300 MW of solar resources in Utah. Because Utah customers are already committed to paying for and receiving the benefits of the output from these resources, the risk of loss of load events will be reduced even further during daylight hours when they are generating. The scenario "2019 Utah Load Net of Contracted Utah Solar" takes 2019 hourly actual Utah load and subtracts from it 1.8 times the 2019 hourly actual generation from utility-scale solar resources in Utah. Multiplying by 1.8 corresponds to the ratio of the contracted solar capacity in Utah in 2019 (855 MW) and the total after executed contracts are included (1,550 MW at the time of rebuttal). When this larger amount of utility-scale solar generation is netted out, more daytime hours drop out of the top 10 percent, resulting in a lower capacity contribution. If generation capacity credits were to be set at a fixed level for a number of years, it would be appropriate to account for the impact of committed contracts over that time frame, as represented by this scenario.

Q. The October Order stated that "the capacity contribution values advocated by VS include only resources currently operating, while RMP's proposed capacity contribution values include planned future resources."[8] Is this accurate?

A. No. As shown in Table 2, my rebuttal testimony provided a variety of capacity contribution values which did not include planned future resources. In addition, Dr. Milligan's proposals did not account for any utility-scale resources that were currently operating.

[8] October Order at 15.

Q. Did Dr. Milligan confirm that his capacity contribution calculations did not account for any utility-scale resources?

A. Yes. At the hearing, Dr. Milligan responded "Yes" when asked: "is it true that your capacity contribution calculation, the one that we were talking about — or that you were talking about in your summary, you didn't account for utility scale solar, you only accounted for customer generated solar?"[9]

Q. Did Dr. Milligan also confirm that the solar capacity on a system affects the capacity contribution of solar?

A. Yes. At the hearing, Dr. Milligan stated that "the more solar you have in the system the more the capacity contribution declines." He went on to caveat that capacity contribution is "not a function purely of solar, it's a function of all the other resources."[10]

Q. Does Dr. Milligan's methodology account for any utility-scale resources?

A. No. Dr. Milligan's capacity contribution methodology is solely based on load and the limited CG production incorporated in the load forecast.

Q. What resources do you expect would have the greatest impact on the capacity contribution of solar?

A. Energy storage resources are likely to have synergistic effects, such that the total capacity contribution in a portfolio that includes solar will be higher than if either energy storage or solar were incorporated in the portfolio on their own.

[9] See Oct. 2, 2020 Hearing Transcript pg. 809-810
[10] See Oct. 2, 2020 Hearing Transcript pg. 809

Q. Does RMP anticipate adding a significant quantity of energy storage resources to its portfolio in 2021?

A. No. While RMP is likely to incorporate some energy storage capability via its arrangement with Soleil Lofts[11] and its Wattsmart Batteries program under Schedule 114[12], any synergistic benefits from these programs are likely to be dwarfed by solar resource additions. Over the longer term, energy storage and combined solar and energy resources featured prominently in PacifiCorp's 2019 IRP preferred portfolio; however, energy storage additions are likely to slow the decline in solar resource capacity contributions, rather than increase them, especially if they are added in combination with solar resources as the solar component would push solar capacity contributions down.

Q. In light of the Commission's determination that the export credit rate should be updated annually, do you have an alternative generation capacity contribution proposal that is applicable to a 2021 rate effective period?

A. Yes. Not all of the roughly 700 MW of contracted solar resources included in the "2019 Utah Load Net of Contracted Utah Solar" scenario are expected to reach commercial operation before the summer of 2021. Approximately 460 MW of solar resources have come online since 2019 or are expected to be online by April of this year, prior to the summer season that drives the Company's peak generation requirements in Utah. This represents approximately 54 percent more utility-scale solar capacity than was online

[11] Soleil Lofts all-electric residential community named 2019 Project of the Year. www.rockymountainpower.net/about/newsroom/news-releases/soleil-lofts-project-of-the-year.html

[12] Utah Schedule 114: Load Management Program. www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/114_Load_Management_Program.pdf

in 2019, somewhat lower than the 81 percent increase when all signed contracts at the time of rebuttal were included. Using this level of utility-scale solar penetration results in a capacity contribution of approximately 6.49 percent, or approximately 7.16 percent when avoided line losses are accounted for. These results are shown in Table 2 in the scenario "2019 Utah Load Net of 2021 Utah Solar".

Q. Does the Company's recommended generation capacity contribution methodology allow for annual updates that are relatively easy to review?

A. Yes. The Company's recommended generation capacity contribution methodology would rely on actual hourly CG exports, actual Utah load, and actual Utah utility-scale solar generation. It also accounts for contracted solar resources that will be online during the rate effective period. Because none of this information requires production cost modeling, regression, or other complicated calculations it should be relatively straightforward for parties to review.

Transmission Capacity Contribution

Q. What transmission capacity contribution did the Commission approve in its October Order?

A. The October Order states that the Commission is approving the capacity contribution value proposed by VS and applying that same value to the avoided generation, transmission, and distribution capacity costs.[13] While the October Order did not explicitly identify the capacity contribution that was approved, it does identify the resulting avoided capacity costs that can allow for the underlying capacity contribution to be identified.

[13] October Order at 15

The Commission's avoided transmission capacity cost value of 0.91 cents/kWh represents a reduction of approximately 17 percent from a value of 1.10 cents/kWh. This discount represents the difference between a 9.39 percent annual carrying charge proposed by parties and a 7.82 percent annual carrying charge. Using an annual cost of transmission capacity of $32.74/kilowatt/year, an energy to capacity ratio of 896.27 kWh/kilowatt, a line loss gross up of 9.08 percent, and a capacity contribution of 27.65 percent results in a 2021 capacity payment of 1.10 cents/kWh.[14]

Q. Are transmission capacity contribution values necessarily the same as generation capacity contribution values?

A. No. The basis of generation capacity contribution is reasonably agreed upon to be related to the risk of generation capacity shortfalls, which in turn are related to the supply of resources, which changes over the course of a day and across the year. In contrast, a transmission capacity shortfall represents a need for additional transfer capability to bring resources to load. To the extent RMP has adequate transmission to deliver its utility-scale solar resources to load during the day, that same transmission will continue to be available during periods when loads are lower, even though the risk of generation capacity shortfalls may be higher as utility-scale solar comes offline in the evening. As a result, while the resource mix is an important factor in generation capacity contribution, peak transmission system deliveries are more relevant to transmission capacity contribution. Therefore, it could be reasonable to develop a transmission capacity contribution without netting out any generation resources, for instance the top 10 percent of hours in the "2019 Utah Load" scenario in Table 2.

---

[14] ($32.74/kW-yr * 27.65% *109.08% / 896.27 kWh/kW) * 100 cents/$ = 1.10 cents/kWh

Q. What is the source of the avoided transmission costs proposed by VS?

A. VS witness Dr. Yang has proposed that avoided transmission costs be based on PacifiCorp's OATT rate for firm transmission service. The same rate applies to both point-to-point transmission service and NITS.

Q. Which transmission service is applicable to Utah retail loads?

A. The Company generally serves retail customers in Utah using NITS provided by PacifiCorp Transmission.

Q. Are the top 10 percent of load hours used to determine transmission costs under PacifiCorp's OATT?

A. No. Under the OATT, the cost of NITS is based on a transmission customer's hourly load coincident with PacifiCorp Transmission's Monthly Transmission System Peak.[15] The hours in which the Monthly Transmission System Peak occurred are identified as part of PacifiCorp's annual transmission formula rate update, and are publicly available.[16] Note that utility-scale solar resources do not reduce the Monthly Transmission System Peak as they are delivered to retail customers across the transmission system, while CG can reduce the use of the transmission system during peak requirements.

Q. Are CG exports expected to contribute to savings during the Monthly Transmission System Peak in every month?

A. No. In five months of 2019 (mainly in the winter), the VS CG export profile was zero

[15] See PacifiCorp Open Access Transmission Tariff. Section 34. (Updated January 8, 2021). Available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20210108_OATTMASTER.PDF (accessed 2/19/2021)
[16] See PacifiCorp's OASIS website: https://www.oasis.oati.com/ppw/index.html. From the menu, select: PacifiCorp OASIS Tariff/Company/Information → OATT Pricing → 2020 Transmission Formula Annual Update → 2019 True-up (accessed 2/19/2021)

during the Monthly Transmission System Peak. In addition, because the Monthly Transmission System Peak is a single hour, it includes significantly fewer hours than the top 10 percent load hour calculation proposed by Dr. Milligan. It also represents an equal weighting of each month, whereas the top 10 percent Utah load hours are entirely in the summer months of June through September, with 78 percent of the top hours occurring in July and August.

Q. Have you calculated a transmission capacity contribution consistent with the Monthly Transmission System Peaks used to determine transmission costs under the OATT?

A. Yes. Based on the VS export profile from 2019 and the 2019 Monthly Transmission System Peaks, the transmission capacity contribution is approximately 7.72 percent, or 8.46 percent after grossing up for losses.

Q. Is it reasonable to apply the same loss factor to generation capacity and transmission capacity?

A. Yes.

Q. Does the Company's recommended transmission capacity contribution methodology allow for annual updates that are relatively easy to review?

A. Yes. The Company's recommended transmission capacity contribution methodology would rely on actual hourly CG exports and the publicly available Monthly Transmission System Peaks. Since this information does not require production cost modeling, regression, or other complicated calculations it should be relatively straightforward for parties to review.

Distribution Capacity Contribution

Q. What distribution capacity contribution did the Commission approve in its October Order?

A. The October Order states that the Commission approves the capacity contribution value proposed by VS and applies that same value to the avoided generation, transmission, and distribution capacity costs.[17] While the October Order did not explicitly identify the capacity contribution that was approved, it does identify the resulting avoided capacity costs that can allow for the underlying capacity contribution to be identified.

The Commission's avoided distribution capacity cost value of 0.31 cents/kWh represents a reduction of 27.5 percent from a value of 0.425 cents/kWh proposed by VS. This 27.5 percent discount represents the difference between the 10.79 percent annual carrying charge proposed parties and the Commission ordered value of 7.82 percent. Using a cost of distribution capacity of $122.73/kw, a carrying charge of 10.79 percent, an energy to capacity ratio of 896.27 kWh/kW, a line loss gross up of 4.62 percent, and a capacity contribution of 27.49 percent results in a 2021 capacity payment of 0.425 cents/kWh.[18]

Q. Are distribution capacity contribution values necessarily the same as transmission capacity contribution values?

A. No. Transmission costs under PacifiCorp's OATT are determined from Monthly Transmission System Peaks. In contrast, Utah distribution costs are entirely allocated to Utah customers. As a result, it is more reasonable to develop a distribution capacity contribution based on Utah load, rather than system load, and without netting out any

[17] October Order at 15
[18] ($123/kW *10.79%/yr * 27.65% *104.62% / 896.27 kWh/kW) * 100 cents/$ = 0.43 cents/kWh

utility-scale resources that would be delivered across the transmission system, for instance the top 10 percent of hours in the "2019 Utah Load" scenario in Table 2. For the same reasons described in the discussion of generation capacity contribution, it is most appropriate to use load and export data from the same time period to determine a distribution capacity contribution, rather than comparing a forecast and actuals that represent different underlying conditions. This approach results in the Company's proposed distribution capacity contribution of 21.99 percent prior to accounting for losses.

Q. Is it necessary to apply a different line loss gross up to distribution capacity contribution, relative to what is applicable to the generation capacity contribution?

A. Yes. The "2019 Utah Load" scenario in Table 2 has a capacity contribution of 21.99 percent prior to accounting for losses. When grossed up by the 4.62 percent distribution loss factor proposed by VS, the effective distribution capacity contribution is 23.01 percent, including losses.

Q. Does the Company's recommended distribution capacity contribution methodology allow for annual updates that are relatively easy to review?

A. Yes. The Company's recommended distribution capacity contribution methodology would rely on hourly actual CG exports and actual Utah load. This information does not require production cost modeling, regression, or other complicated calculations it should be relatively straightforward for parties to review.

Generation Capacity Carrying Charge

Q. What generation capacity carrying charge did the Commission approve in its October Order?

A. The October Order states that the Commission applied a carrying charge of 7.82 percent to the generation, transmission, and distribution avoided capacity costs.[19]

Q. What does the 7.82 percent carrying charge represent?

A. This value represents the proportion of the upfront capital costs of a simple cycle combustion turbine ("SCCT") that would be collected in each year in order to ensure full recovery over an assumed asset life of 20 years. The actual collections are assumed to be constant in real dollars, so on a nominal basis they grow at inflation over time.

Q. Is a carrying charge the same as the Company's cost of capital and cost of debt, often referred to as the weighted average cost of capital ("WACC")?

A. No, though they are related. The WACC represents the incremental cost of debt and equity obligations used to support capital investments and represents the additional cost of those obligations over each year. A carrying charge represents the cost of paying off an investment in each year of an asset's expected life, and that annual cost includes both the repayment of the initial capital as well as the incremental cost of borrowing or equity-funding that capital. As a result, a higher WACC would result in a higher carrying charge. However, a higher WACC would not affect the repayment of initial capital, so the carrying charge would not be affected to the same degree as the WACC.

Q. Can you provide an example?

A. Yes. The 7.82 percent carrying charge referenced above reflects the cost of a SCCT

[19] October Order at 16

spread over a 20-year asset life. 20 years times 7.82 percent/year is 156.4 percent, with the 100 percent representing the repayment of the capital cost and 56.4 percent representing the incremental cost of capital (both in real dollars). For an asset with a longer life, the repayment of the capital cost is lower in each year, but this effect is offset by a higher incremental cost of capital as the amount of the initial investment that remains to be repaid is higher in each year.

Q. The October Order suggests that your rebuttal testimony proposed applying the 7.82 percent carrying charge. Did your rebuttal testimony support the use of this value?

A. No. My rebuttal testimony explicitly stated that the carrying charge from the Utah marginal cost of service study was not appropriate for determining avoided costs.[20]

Q. Why is the Utah marginal cost of service study inappropriate for setting avoided costs?

A. The marginal cost of service study is only intended to produce a reasonable allocation of revenue requirement amongst customer classes. It does not determine the total revenue requirement collected from customers overall, which instead reflects the depreciable life of each asset.

The Commission's initially-approved capacity costs are based on Dr. Milligan's sur-rebuttal testimony, which uses SCCT resource costs from the Company's 2019 IRP. The 2019 IRP assumed that this resource has a 35-year life. If a carrying charge is based on a 20-year life, as in the marginal cost of service study, the resource would be fully paid for in 20 years and would be provide operational benefits for an additional

[20] *See* lines 837-844 of RMP witness Mr. Daniel MacNeil's Rebuttal Testimony.

15 years without any capital cost. While this could be managed in rate base, it would result in a cliff in capacity payments in year 21. In the alternative, if a carrying charge based on a 20-year life was continued for the full 35-year life of the SCCT, it would result in a significant overpayment. With CG exporting customers entering and leaving over time, and with avoided capacity costs likely to vary over time, it would not be equitable to use a carrying charge that is different from the assumed asset life as this would shift costs between current and future ratepayers.

Q. Do you agree with the Commission's adjustment for carrying charges in the generation capacity cost?

A. No. My rebuttal testimony identified that the next thermal resource in the 2019 IRP preferred portfolio (a brownfield SCCT at the Naughton site) has an assumed fixed cost of $88/kilowatt/year (2026$).[21] This includes the annual capital costs and fixed operations and maintenance ("O&M") associated with the project, and reflects a carrying charge of approximately 6.96 percent, consistent with the assumption in the 2019 IRP. The generation capacity cost proposed in Dr. Milligan's sur-rebuttal testimony used this cost of $88/kilowatt/year, adjusted for inflation back to 2021, so he has already incorporated a carrying charge of 6.96 percent. My rebuttal testimony identified this carrying charge and indicated that the long-term assumption in the 2019 IRP was more appropriate than the marginal cost of service assumption.[22] I continue to support using 6.96 percent as the carrying charge for this resource, and agree that Dr. Milligan has incorporated it, so no adjustment for carrying charges is necessary.

[21] *See* lines 763-766 of RMP witness Mr. Daniel MacNeil's Rebuttal Testimony.
[22] *See* lines 845-858 of RMP witness Mr. Daniel MacNeil's Rebuttal Testimony.

Q. Please illustrate your proposed generation capacity credit.

A. Table 3 illustrates the calculations underlying the generation capacity credit approved in the Commission's October Order, along with the Company's proposed generation capacity credit of 0.62 cents/kWh.

Table 3: Generation Capacity Credit (2021$)

Row	VS	RMP SSR	Units	Description
a	*[$642.06]*	$642.06	$/kw	Capital Cost
b	*[6.96%]*	6.96%	%	Carrying Charge
c	*[$34.00]*	$34.00	$/kw-yr	Fixed O&M
d = a*b+c	$78.61	$78.68	$/kw-yr	Annual Capacity Cost (i)
e	28.96%	6.49%	%	CG Export Capacity Contribution Before Losses (ii)
f(iii)	109.08%	109.08%	%	Line Loss Gross up
g	100	100	cents/$	Dollars to cents conversion
h(iii)	896.27	896.27	kWh/kW	Annual CG Export Energy per kW
i = d*e*f*g / h	2.77	0.62	cents/kWh	Generation Capacity Credit
j	9.39%	n/a	%	Carrying charge originally proposed by parties
k	7.82%	n/a	%	Commission ordered carrying charge
l = 1 - k / j	16.7%	n/a	%	Commission Adjustment
m = I * (1 - l)	2.31	n/a	cents/kWh	Generation Capacity Credit: October Order

i) Dr. Milligan's sur-rebuttal value of $78.61/kw-yr is $88/kw-yr (2026$) less five years of inflation at 2.28% and varies slightly due to rounding.
ii) Dr. Milligan's sur-rebuttal capacity contribution value for 2021 is already grossed up for line losses.
iii) Items (f) and (h) were used in Dr. Milligan's sur-rebuttal proposal and were not subject to rehearing.

Q. Do the capital cost, carrying charge, and fixed operation and maintenance ("O&M") costs included in Table 3 represent the entirety of the cost of service or revenue requirement impact of a SCCT?

A. No. The Company would also incur fuel costs and variable O&M costs whenever the resource is brought online. In addition, any generation produced or operating reserves held by the facility would avoid the need for energy and operating reserves from other sources. Because the Company controls the SCCT operation and can leave it offline when conditions are unfavorable, the value of the energy and operating reserves will generally exceed the variable costs of operations. The associated benefits would be reflected in reduced net power costs, and a lower revenue requirement. In 2019, the net generation of the Company's Gadsby combustion turbines equated to a capacity factor of approximately 2 percent. In 2020, the capacity factor of the Gadsby combustion turbines was more than twice as high. In addition, while they are called upon infrequently, the value when they are dispatched can be well in excess of their variable operating costs, resulting in a reduced revenue requirement in the net power costs set in base rates and in the annual Energy Balancing Account true-up under Schedule 94.

Q. Is there an existing process by which the Company calculates the expected revenue requirement impact of avoided generation resources including the value of economic dispatch?

A. Yes. The Commission has approved the partial displacement differential revenue requirement methodology ("PDDRR") to calculate avoided costs for qualifying facilities. This methodology and the importance of ensuring that capacity costs account for both fixed costs net of the energy value and other benefits a capacity resource provides was discussed in my rebuttal testimony.[23]

Q. Is the Company proposing that the Commission account for the variable dispatch benefits of a SCCT in the generation capacity credit?

A. Not at this time, as this topic appears to be outside of the scope of the Commission's

[23] *See* lines 760-829 of RMP witness Mr. Daniel MacNeil's Rebuttal Testimony.

rehearing order.

Transmission Capacity Carrying Charge

Q. What transmission capacity carrying charge did the Commission approve in its October Order?

A. The October Order states that the Commission applied a carrying charge of 7.82 percent to the generation, transmission, and distribution avoided capacity costs.[24]

Q. Do you agree with the Commission's adjustment for carrying charges in the transmission capacity cost?

A. No. The transmission capacity cost proposed by VS is $32.74/kilowatt/hour, which is already an annual revenue requirement and does not incorporate a disputed carrying charge.

Q. Please illustrate your proposed transmission capacity credit.

A. Table 4 illustrates the calculations underlying the transmission capacity credit approved in the Commission's October Order, along with the Company's proposed transmission capacity credit of 0.31 cents/kWh.

[24] October Order at 16

Table 4: Transmission Capacity Credit (2021$)

Row	VS	RMP SSR	Units	Description
a	$32.74	$32.74	$/kw-yr	Annual Capacity Cost (i)
b	27.65%	7.72%	%	CG Export Capacity Contribution Before Losses (ii)
c(iii)	109.08%	109.08%	%	Line Loss Gross up
d	100	100	cents/$	Dollars to cents conversion
e(iii)	896.27	896.27	kWh/kW	Annual CG Export Energy per kW
f = a*b*c*d / e	1.10	0.31	cents/kWh	Transmission Capacity Credit
g	9.39%	n/a	%	Carrying charge originally proposed by parties
h	7.82%	n/a	%	Commission ordered carrying charge
i = 1 - h / g	16.7%	n/a	%	Commission Adjustment
m = I * (1 - l)	0.917	n/a	cents/kWh	Transmission Capacity Credit: October Order (iv)

i) Dr. Yang Sur-rebuttal, line 80
ii) Dr. Milligan's revised affirmative capacity contribution value for 2021-2040, which did not include line losses.
iii) Items (c) and (e) were used in Dr. Milligan's sur-rebuttal proposal and were not subject to rehearing.
iv) The Commission ordered value of 0.91 cents/kWh may reflect independent rounding.

Distribution Capacity Carrying Charge

Q. What distribution capacity carrying charge did the Commission approve in its October Order?

A. The October Order states that the Commission applied a carrying charge of 7.82% to the generation, transmission, and distribution avoided capacity costs.[25]

Q. Do you agree with the Commission's adjustment for carrying charges in the distribution capacity cost?

A. No. The Company agrees that the carrying charge proposed by VS is not appropriate

[25] October Order at 16

for use in this proceeding, but also disagrees with the carrying charge identified by the Commission for distribution assets, which have an asset life that is longer than the twenty-year life used in the marginal cost of service analysis from which the Commission's ordered value of 7.82 percent was derived. Confidential VS Exhibit 2-SSY, submitted with the revised direct testimony of VS witness Dr. Spencer Yang included the Company's assumed carrying charge for Utah distribution system investments, which is 6.51 percent. This value was used to calculate distribution deferral credits applied to energy efficiency resources in the Company's 2019 IRP and is also appropriate to apply to CG exports.

Q. Please illustrate your proposed distribution capacity credit.

A. Table 5 illustrates the calculations underlying the distribution capacity credit approved in the Commission's October Order, along with the Company's proposed distribution capacity credit of 0.21 cents/kWh.

Table 5: Distribution Capacity Credit (2021$)

Row	VS	RMP SSR	Units	Description
a (i)	$122.73	$122.73	$/kw	Capital Cost (after utilization adj.)
b	10.79%	6.51%	%	Carrying Charge
c = a*b	$13.24	$7.99	$/kw-yr	Annual Capacity Cost
e	27.49%	21.99%	%	CG Export Capacity Contribution Before Losses (ii)
f(i)	104.62%	104.62%	%	Line Loss Gross up
g	100	100	cents/$	Dollars to cents conversion
h(i)	896.27	896.27	kWh/kW	Annual CG Export Energy per kW
i = d*e*f*g / h	0.42	0.21	cents/kWh	Distribution Capacity Credit
j	10.79%	n/a	%	Carrying charge originally proposed by VS
k	7.82%	n/a	%	Commission ordered carrying charge
l = 1 - k / j	27.5%	n/a	%	Commission Adjustment
m = I * (1 - l)	0.31	n/a	cents/kWh	Distribution Capacity Credit: October Order

i) Items (a), (f), and (h) were used in Dr. Yang's proposal and were not subject to rehearing.
ii) Dr. Milligan's revised affirmative capacity contribution value for 2021, which did not include line losses.

Conclusion

Q. What is your recommendation for the Commission?

A. I recommend that the Commission approve a capacity credit for CG exports totaling 1.13 cents/kWh, as illustrated in Table 1 above.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.