Selendy & Gay PLLC
Jennifer M. Selendy
Philippe Z. Selendy
Joshua S. Margolin
Margaret M. Siller
1290 Avenue of the Americas
New York, NY 10104
212-390-9000
jselendy@selendygay.com
pselendy@selendygay.com
jmargolin@selendygay.com
msiller@selendygay.com

Attorneys for Vote Solar

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	**Docket No. 17-035-61 Phase 2**

REBUTTAL TESTIMONY OF CURT VOLKMANN

ON BEHALF OF

VOTE SOLAR

July 15, 2020

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I. Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 132 Lake Vista Circle, Fontana, Wisconsin, 53125.

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

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

Q. Did you submit affirmative testimony in this proceeding?

A. Yes. My Revised Affirmative Testimony dated May 8, 2020 includes a summary of my education and professional experience.[1]

Q. Please provide a brief overview of your background and qualifications.

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 36 years of experience in the utilities industry, primarily in electric transmission and distribution. I have testified and commented before regulatory commissions in various distribution planning, grid modernization, and distributed energy resources proceedings in eleven states.

[1] Vote Solar, *Revised Affirmative Testimony of Curt Volkmann*, May 8, 2020, lines 11-21.

II. Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I am rebutting the testimony of Rocky Mountain Power ("RMP") witness Daniel J. MacNeil and Department of Commerce, Division of Public Utilities ("DPU") witness Robert A. Davis. My rebuttal testimony will:

1) Explain why avoided line transformer losses should be included in the customer generation ("CG") export credit.
2) Explain that there is no evidence that CG variability is causing "wear-and-tear" on RMP's distribution equipment.
3) Explain the growing evidence that CG output reduces the need for transmission and distribution capacity additions.
4) Explain how advanced inverters can mitigate voltage concerns related to CG output.
5) Explain why RMP's proposed CG metering fee is arbitrary and excessive.

My lack of comments on any components of other parties' direct testimony should not be interpreted as acquiescence or agreement. I reserve the right to express additional opinions, to amend or supplement the opinions in this testimony, or to provide additional rationale for these opinions as additional documents are produced and new facts are introduced during discovery and trial. I also reserve the right to express additional opinions in response to any opinions or testimony offered by other parties in this proceeding.

III. The CG Export Credit Should Include Avoided Line Transformer Losses

Q. How has RMP quantified losses on its transmission and distribution ("T&D") system?

A. RMP has quantified loss expansion factors for six segments of its T&D system. Figure 1 shows the individual and cumulative energy loss expansion factors for each segment.

	Energy (MWh)	
Segment	**Factor**	**Cumulative**
1) Transmission System	1.04527	1.04527
2) Distribution Substation	1.00665	1.05222
3) Primary Line	1.01342	1.06635
4) Line Transformer	1.01863	1.08621
5) Secondary	1.00141	1.08774
6) Service Drop	1.00504	1.09322

Figure 1[2]

Q. How has the Company proposed to credit CG exports for avoided losses?

A. RMP proposes to credit CG exports for avoided line losses at the transmission and primary levels, which includes the distribution substation and primary line segments. RMP explains: "The Company expects to apply the export credit to resources interconnected at secondary voltage levels. However, the exported energy must be transferred across the secondary distribution system to other customers. As a result, they will incur some line losses and will not be avoiding the entire line losses associated with serving load on the secondary distribution system. Therefore, the Company proposes crediting exports for only avoiding the next higher level, i.e. primary line losses."[3]

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[2] Exhibit 1-CV, PacifiCorp Utah 2009 Analysis of System Losses November 2011.pdf, Appendix B, Exhibit 9, RMP's Responses to Vote Solar 6th Set Data Requests – Attach 6.8 (Aug. 16, 2019).

[3] RMP, *Direct Testimony of Daniel J. MacNeil*, Feb. 3, 2020, lines 148–53.

Q. Do other parties agree with this approach?

A. Yes, DPU witness Abdinasir M. Abdulle states: "First, RMP proposes to adjust the avoided energy costs for line losses. Customers under this program take service at the secondary level. Private generation customers export energy back to the grid across the secondary grid to other customers. RMP proposes to include in export credit rates avoided line losses for transmission and primary levels. This is a reasonable line loss calculation because energy from other generation resources would experience line losses at the transmission, primary, and secondary levels. Private generation customer exports must still transfer across the secondary circuits and will experience line losses in the secondary circuits. Therefore, the appropriate adjustment for line losses is for the transmission and primary levels."[4]

Q. Do you agree with this approach?

A. I agree with RMP and DPU that CG exports avoid losses at the transmission, distribution substation, and primary line segments. However, as I explained in my Revised Affirmative Testimony filed on May 8, 2020, CG exports also avoid line transformer losses.[5] RMP's proposed CG export credit fails to include the line transformer segment.

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[4] DPU, *Direct Testimony of Abdinasir M. Abdulle*, Mar. 3, 2020, lines 45–54.
[5] *Volkmann Affirmative*, lines 240–52.

Q. Please explain how RMP's proposed CG export credit fails to include the line transformer segment.

A. RMP witness MacNeil states that the Company has identified line losses in Utah at the primary interconnection level to be 6.635%.[6] Figure 1 shows that cumulative energy losses of 6.635% only take into account losses on the Transmission System, Distribution Substation, and Primary Line segments. RMP's proposed CG export credit does not include avoided line transformer losses.

Q. How do CG exports avoid line transformer losses?

A. As I explained in my Revised Affirmative Testimony filed on May 8, 2020, the majority of CG exports flow to serve other customers connected to the same distribution line transformer (i.e., via the secondary distribution system)[7], resulting in reduced energy flowing through the transmission and primary distribution systems, including the line transformers. In response to an OCS data request, RMP explains:

> When a customer being served at the secondary voltage level has on-site generation in excess of their load, that generation is transferred through the customer meter and up the service drop. To reach another secondary customer, the generation must at least pass across secondary voltage lines, back down a service drop, and through another customer's meter. Losses are incurred at each stage of this process. The losses across the exporting customer's service drop will be incremental to what would otherwise be required to serve another customer. The losses on another customer's service drop would be the same whether that power is sourced from exported customer generation or utility assets. Losses on secondary voltage lines could be higher or lower depending on the specific circumstances. Additional losses would be incurred to the extent generation must be converted from secondary to primary voltage by the line transformer or from primary to transmission voltage in the distribution substation … Given that exported customer generation uses the secondary distribution system, it will incur losses on the secondary system, so the

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[6] *MacNeil Direct*, line 140.

[7] *Volkmann Affirmative*, lines 71–75.

> Company's proposal does not credit exported generation with avoided secondary losses.[8]

Q. RMP's response above indicates that, in addition to losses on the secondary distribution system, there could be additional losses if excess generation flows through the line transformer or even the distribution substation. Do you agree?

A. I agree that there are some scenarios where CG exports may flow across line transformers to serve adjacent load and incur losses. In extreme cases of high CG penetration on a circuit, when aggregate CG output exceeds the circuit load, excess generation may flow through a utility's distribution substation. However, I believe that with RMP's current CG penetration of only 1.7%,[9] the majority of exports flow to serve other customers connected to the same secondary distribution system. It is therefore reasonable to assume that CG exports avoid line transformer losses.

Q. What do you recommend?

A. I agree that CG exports do not avoid losses on the secondary and service drop segments. However, I continue to recommend that the CG export credit include avoided energy losses from the transmission, distribution substation, primary line, and line transformer segments with cumulative energy losses of 8.621% as shown in Figure 1. Vote Solar witness Milligan quantifies the impact of this recommendation on the CG export credit in his Revised Affirmative Testimony dated May 8, 2020.[10]

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[8] Exhibit 2-CV, *Response to OCS Data Request 3.3*, RMP's Responses to OCS 3rd Set Data Requests (Mar. 10, 2020).
[9] *Volkmann Affirmative*, lines 287–89.
[10] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, May 8, 2020, lines 347–50.

IV. There Is No Evidence That RMP Is Experiencing CG-related "Wear-and-Tear" of Distribution Equipment

Q. Did any party raise concerns about the impact of CG variability?

A. Yes. DPU witness Robert A. Davis explains:

> Electricity, by its very nature, has to have a demand for supplied generation. Customer generation is either consumed on-site or exported to the grid. Many factors, from weather systems, the time-of-day, system failures, etc., can lead to solar customer delivery and export variability throughout the day, month, and year. In real time, solar customers might be pulling from the grid and within an instant exporting to the grid for whatever reason. Of course, such instant changes might be localized to a few customers or spread more broadly. The distribution system and fleet generation resources have to be available and adjust accordingly to keep the system reliable. This likely leads to additional wear- and-tear.[11]

Mr. Davis further states: "It is a reasonable assumption that additional variability has the potential to wear out certain distribution equipment at a faster rate than otherwise would occur."[12] He also states: "Although distribution equipment is designed to meet load under such variable conditions, the addition of weather related or other solar induced variability attributes likely cause additional wear-and-tear on system components."[13]

Q. Did Vote Solar request additional information from the DPU on this alleged issue?

A. Yes. In response to Vote Solar data requests seeking documents or other evidence supporting this concern, the DPU stated: "The Division has not compiled a comprehensive list of every published work on the topic as there are too many studies, white papers, and articles on this topic to cite or mention here."[14] In the same data request response, the DPU

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[11] DPU, *Direct Testimony of Robert A. Davis*, Mar. 3, 2020, lines 339–47.
[12] *Id*. at lines 186–88.
[13] *Id*. at lines 226–29.
[14] Exhibit 3-CV, *Response to Vote Solar Data Request 2-1.1*, DPU's Responses to Vote Solar 2nd Set Data Requests (June 8, 2020).

provided various presentations and links to additional documents, none of which provide evidence of "wear-and-tear" on RMP's distribution system.[15] Oddly, the DPU also cited a 2013 technical white paper, which concludes that high penetrations of PV can significantly extend distribution transformer life.[16] This directly contradicts the DPU's concern about "wear-and-tear."

Q. Did DPU witness Davis provide an estimate of how significant this issue is?

A. No. DPU witness Davis expressly acknowledges that any "wear-and-tear" cannot be quantified, stating: "The wear-and-tear is difficult to estimate with any accuracy because the equipment in question is designed to operate for sometimes 50-70 years or thousands of cycles,"[17] and, "The Division cannot quantify how the variability impacts the system at this time[.]"[18]

[15] The documents provided by the DPU include four presentations from the Utah PSC's July 11, 2019 technical workshop on distributed solar grid impacts conducted by Lawrence Berkley National Laboratory and Pacific Northwest National Laboratory, and a 2017 NERC report on DER reliability considerations, which does not mention the issue of distribution equipment "wear-and-tear". *See* Exhibit 3-CV.

[16] Exhibit 3-CV (citing H. Pezeshki, P. J. Wolfs and G. Ledwich, *Impact of High PV Penetration on Distribution Transformer Insulation Life*, IEEE Transactions on Power Delivery, vol. 29, no. 3, pp. 1212-1220, June 2014, available at https://core.ac.uk/download/pdf/19541682.pdf).

[17] *Davis Direct*, line 188 n. 14.

[18] *Id*. at lines 188–89.

Q. Can RMP provide evidence of distribution equipment "wear-and-tear" from CG variability?

A. No. In response to Vote Solar data requests, RMP provided no evidence that the variability of CG output reduces equipment life.[19] RMP also acknowledges that it does not track any increases in line equipment maintenance costs due to the variable output of CG.[20]

Q. What do you conclude?

A. There is no evidence that RMP is experiencing "wear-and-tear" of distribution equipment due to CG variability. DPU witness Davis acknowledges this fact, stating: "I have no evidence at the time of this filing to indicate if there are system issues at the current penetration level because of customer generation."[21]

V. Despite its Variability, CG Output Reduces the Need for T&D Capacity Investments

Q. Has RMP included a T&D capacity deferral or avoidance value in its proposed CG export credit methodology?

A. No.

[19] Exhibit 4-CV, *Response to Vote Solar Data Request 6.24(19)*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 23, 2019). RMP's response consists of user manuals for single-phase voltage regulators and pole-mounted three-phase capacitor banks, neither of which mentions the issue of reduced equipment life from CG.

[20] Exhibit 4-CV, *Response to Vote Solar Data Request 6.24(20)*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 23, 2019).

[21] *Davis Direct*, lines 349–50.

Q. Did any party testify about the impact of CG on T&D capacity?

A. Yes. DPU witness Davis states: "Solar generation is an intermittent resource that produces during daylight hours. The downside to the technology is that it can drop off and return over short periods of time or remain marginal for longer periods of time. It is a challenge to forecast when these cycles might occur making its capacity contribution low."[22]

Q. Do you agree?

A. I agree that CG is an intermittent resource. However, despite its variability, there is growing evidence that CG materially reduces peak loads and the associated need for capacity-related capital investments.

Q. Please provide an example of this.

A. The California Public Utilities Commission ("CPUC") has established an Avoided Cost Calculator to determine the primary benefits of distributed energy resources ("DER"). The Avoided Cost Calculator calculates six types of avoided costs: energy, generation capacity, T&D capacity, ancillary services, renewable portfolio standard compliance, and greenhouse gas emissions. The outputs of the Avoided Cost Calculator feed into the utilities' cost-benefit analysis for DER across various CPUC proceedings.[23]

In its April 2020 decision, the CPUC acknowledged that DER avoid both specified and unspecified transmission investments. Specified transmission investments are those tied to specific capital projects. Unspecified transmission investments refer to future capacity

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[22] *Davis Direct*, lines 321–24.

[23] CPUC, *2020 Policy Updates to the Avoided Cost Calculator*, California Public Utilities Commission, D.20-04-010, at 4, Apr. 16, 2020, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K734/334734544.PDF.

upgrades across the system that are no longer needed due to shifts or decreases in load from DER. The CPUC confirmed that, while difficult to quantify, the value for unspecified transmission avoided costs is not zero and directed staff to develop a common methodology for quantifying the values across the state's investor-owned utilities.[24]

Q. Please provide another example of how CG reduces the need for T&D capacity investments.

A. In the current Southern California Edison ("SCE") General Rate Case ("GRC") proceeding, SCE applied a new methodology for "PV Dependability" resulting in significant reductions in its distribution load forecasts and associated distribution capital investments.

Q. What is PV Dependability?

A. PV Dependability is the amount of CG (measured in percentage of nameplate rating) that SCE can reasonably rely on each hour of the day to reduce distribution circuit peak loads, taking into account local conditions such as solar insolation, cloud cover, and temperature.

Q. How does this differ from the Resource Capacity Value calculated by Vote Solar witness Milligan in this proceeding?

A. As Vote Solar witness Milligan explains, the Resource Capacity Value is a measure of the contribution of a generation resource to system-wide generation planning reserves.[25] Dr.

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[24] *Id*. at 3.

[25] *Milligan Affirmative*, lines 372–74.

Milligan appropriately determined that the Resource Capacity Value of CG exports across RMP's system averages 29.51% of the rated installed capacity.[26]

PV Dependability measures the hourly contribution of CG to reducing local distribution peak loads. Because PV Dependability is strongly influenced by local conditions, SCE has established eight regional curves for each of its distribution planning regions.

Q. What is the impact of SCE's new PV Dependability methodology?

A. SCE explains, "[the] updated methodology applied to the 10-year forecast results in a greater amount of solar PV output considered dependable for planning purposes, an increase in the load-modifying impacts, and a corresponding decrease in net load growth."[27] Figure 2 shows that SCE now considers 45% of the installed nameplate of CG as dependable at 12:00 p.m. for its San Jacinto Region and 11.6% at 5:00 p.m., a significant increase from the assumptions in its 2018 GRC application.

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[26] *Id.* at lines 534–35.

[27] Solar Energy Industries Association and Vote Solar, *Direct Testimony of Curt Volkmann*, California Public Utilities Commission, Docket No. A.19-08-013, lines 9:15-10:2, May 5, 2020, http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/AD6EA44AD9798A5588258591004D91C0/$FILE/SEIA%20VoteSolar%20Direct%20Testimony%20C.%20Volkmann.pdf.

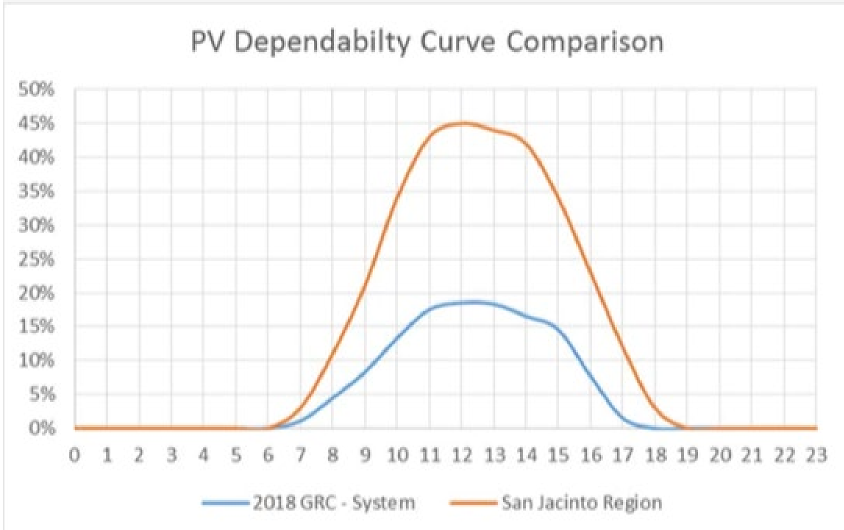

Figure 2[28]

SCE further explains, "The result of increased PV output as dependable is a further reduction in forecasted [distribution] peak loading."[29]

Q. What is the impact of the reduction in forecasted distribution peak loading?

A. The reduction in forecasted distribution peak loading from CG adoption resulted in significant reductions in the need for capacity-related capital investments. As one example, SCE explains:

> The Circle City 66/12 kV Substation Project was originally proposed as a single project that combined two primary scope elements: 1) a new 66/12 kV distribution substation (Circle City Substation), and 2) a new 66 kV subtransmission line (Mira Loma-Jefferson 66kV Line) .... In recent planning cycles, the anticipated load growth in the area has not materialized at the rate previously expected and may be attributed to a reduction in the forecast due to increased DER[30] adoption .... The amount of load growth-reducing DER adoption that is included in its 2019-2028 forecast resulted in a total of 35.24 MW over the 10 years. This amount alone is enough to

[28] Southern California Edison, *SCE's Dependable Photovoltaic Generation Methodology*, California Public Utilities Commission, Docket No. A.19-08-013, Workpaper - Exhibit No. SCE-02 Vol.04 Pt 02 Ch II Bk A, at 12, http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/DD4E0AE29C3D2FCF8825846600789C18/$FILE/WPSCE02V04Pt02ChIIBkA.pdf.

[29] *Volkmann*, California Public Utilities Commission, Docket No. A.19-08-013, lines 16:17-18.

[30] In SCE's service territory, the vast majority of DER is PV CG.

> suppress the projected peak demand to levels that do not support the need for the Circle City Substation scope of the proposed project within the 10-year horizon. Accordingly, SCE has informed the [Commission] of this portion of scope being removed from the project.[31]

Q. What are the associated savings from the reduced project scope?

A. The original project cost was approximately $154 million. Excluding the Circle City Substation, the project cost is now $89.6 million, meaning the load-reducing CG adoption has saved approximately $64 million of capital costs.[32]

Q. What do you conclude?

A. RMP has failed to consider the impact of CG exports on the deferral or avoidance of capital expenditures in its proposed export credit methodology. CG's impact on reducing peak loads and the associated need for T&D capital expenditures can be significant, and the CG capacity deferral value should be included in the export credit. As Vote Solar witness Yang explains, the value of avoided T&D capacity costs due to CG exports in RMP's service territory is at least 2.02 cents/kWh in 2021 dollars.[33]

VI. RMP Can Mitigate Voltage Issues with Advanced Inverters

Q. Did any party raise concerns about CG's impact on circuit voltage?

A. Yes. DPU witness Davis raises a concern about increased voltages from CG output. He states: "The National Renewable Energy Laboratory studies distributed generation to gain an understanding of bi-directional power flows on traditional distribution systems. When

[31] *Volkmann*, California Public Utilities Commission, Docket No. A.19-08-013, lines 16:22-17:13.
[32] *Id.* at lines 17:15-18.
[33] Vote Solar, *Revised Affirmative Testimony of Spencer S. Yang*, Mar. 3, 2020, lines 42-46.

power is injected into the electric system, the voltage at the location increases such that high penetrations of Distributed Generation Photo Voltaic ("DGPV") might raise the voltage beyond the acceptable range, requiring the addition of voltage-regulating equipment."[34] Mr. Davis did not quantify how much additional voltage-regulating equipment may be required.

Q. Do you share this concern?

A. I agree that CG output can raise circuit voltages; however, advanced (or "smart") inverters have the ability to effectively mitigate voltage concerns and reduce or eliminate the need for additional conventional voltage-regulating equipment.

Q. What is an inverter?

A. An inverter is an electronic device that converts direct current ("DC") electricity to alternating current ("AC") electricity. Some DER, such as PV and batteries, require inverters to interconnect to the distribution system. PV systems convert solar energy into DC electricity. Batteries produce and absorb energy in the form of DC electricity. Because the North American electricity system is AC, inverters are necessary for energy from PV solar and batteries to be delivered into the distribution grid or used on site.

Conventional inverters have very limited activated functionality beyond converting DC to AC. They are required to quickly disconnect from the grid when they detect system disturbances such as high/low voltage or frequency.

[34] *Davis Direct*, lines 358–63.

Q. What is an advanced or smart inverter?

A. In markets where PV penetrations are high (i.e., Germany, Hawaii, California), the automatic disconnection of large numbers of inverters during system disturbances became or could become problematic and actually worsen system stability. To address this issue, the industry developed new technical requirements and a revised industry standard for inverters to stay connected or "ride-through" system disturbances within certain ranges to enhance system stability. Advanced or smart inverters are those compliant with the new industry standard and also include new capabilities.

Q. What is the new industry standard, and how does it define new smart inverter capabilities?

A. The new industry standard is the revised Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547-2018, titled the *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* ("IEEE Standard"). The IEEE Standard was approved on February 15, 2018 and published in April of that year.[35]

The IEEE Standard includes categories of DER performance during normal operating conditions[36] and categories of performance for addressing reliability/stability needs during abnormal operating conditions.

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[35] IEEE Standards Association, *1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, Feb. 15, 2018, https://standards.ieee.org/standard/1547-2018.html.

[36] The IEEE Standard defines normal operating conditions as the continuous operation region when the voltage is between 0.88 and 1.1 times the nominal voltage. In North America, the nominal distribution voltage is 120 volts ("V"). Applying the definition of the IEEE Standard means normal operating conditions in North America are when the distribution voltage is between 105.6 V and 132 V.

Q. What are the IEEE Standard's required functions during normal operating conditions?

A. Among other functions, the IEEE Standard requires DER to be able to inject or absorb reactive power to keep voltages within an allowable range during normal operating conditions and to curtail real power[37] output if needed to meet apparent power[38] constraints.

Q. What is RMP's allowable range of distribution voltages?

A. RMP's single-phase service voltage Range A (Favorable Zone), in which the voltage level is near optimal, is between 114-126 V. The Company's Range B (Tolerable Zone), in which the voltage level is acceptable but not optimal, is between 110-127 V. RMP states that its "supply systems are designed and operated so that most service voltage levels are within the limits specified for Range A. The occurrence of steady-state service voltages outside these limits shall be infrequent."[39]

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[37] AC electricity systems must serve loads that consume real and reactive power. Real power, measured in watts ("W"), does useful work and is consumed by loads such as incandescent light bulbs and resistance heating elements. Reactive power, which is unique to AC power systems and measured in Volt-Amperes Reactive ("var"), performs no useful work and is required due to the characteristics of inductive or capacitive circuit loads. Many common AC devices such as fluorescent lights, motors, air conditioning compressors, and power supplies are reactive power loads. Utilities must continuously balance the supply and demand of both real and reactive power. An imbalance in the supply and demand of real power results in fluctuations above or below the system's nominal frequency. An imbalance in the supply and demand of reactive power results in fluctuations above or below nominal system voltage.

[38] Distribution utilities deliver what is called apparent power, measured in Volt-Amperes ("VA"), to supply the real and reactive power consumption in various loads. Manufacturers provide sizes or ratings of AC power equipment in terms of apparent power, often in thousands of Volt-Amperes ("kVA"), or millions of Volt-Amperes ("MVA").

[39] *PacifiCorp Engineering Handbook, 1C.2.1 - Voltage Level and Range*, at 3-4, Apr. 8, 2013, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/pp-rmp/power-quality-standards/1C_2_1_PF.pdf.

Q. Is it common for distribution system voltages to fluctuate within the allowable range?

A. Yes, it is very common for distribution circuit voltages to fluctuate within this range, or even temporarily outside the range, as circuit loads increase and decrease. Distribution systems are designed and constructed to adjust for these fluctuations and remain within the allowable range or to maintain a target voltage level.

Q. How do utilities ensure that distribution voltages remain within the allowable range?

A. Distribution utilities typically install transformer load tap changers, voltage regulators, and capacitors to manually or automatically adjust voltages and power factor, an activity referred to as voltage regulation. When automated, this conventional equipment can adjust voltages to acceptable ranges or pre-determined levels within minutes.

Q. Will smart inverters help utilities regulate voltage during normal operating conditions?

A. Yes. By injecting or absorbing reactive power within seconds at the location of a grid need, smart inverters and other advanced power electronics can significantly improve the speed and level of precision of distribution voltage regulation.

Q. How do smart inverters perform these functions?

A. Smart inverters perform these functions autonomously, meaning no communications or control is required. The functions are activated, and settings established, at the time of initial DER installation, and no additional interactions with the inverters are necessary.

Q. Is RMP aware of these smart inverter capabilities?

A. Yes. RMP conducted a study in 2018 with the Electric Power Research Institute ("EPRI") to determine the potential impact of advanced inverters on its distribution circuits. The final report states: "By absorbing or injecting reactive power, smart inverters may be able to increase hosting capacity on certain feeders by reducing voltage variations resulting from increased generation."[40]

Q. What are the preferred smart inverter modes and settings for voltage regulation?

A. A 2019 GridLab publication[41] (which I co-authored) recommends the Voltage-reactive power ("volt-var") mode with reactive power priority using the IEEE Standard Category B[42] default volt-var settings.

Q. What is volt-var mode?

A. The volt-var mode means the autonomous control of reactive power as a function of voltage. The IEEE Standard default volt-var settings for Category B DER are shown in Figure 3 below. When the voltage at the inverter is between 98% and 102% of the nominal voltage (called the dead band), the inverter does not supply or absorb reactive power. Outside these voltage ranges, the DER inverter begins supplying or absorbing reactive power up to a maximum of 44% of the DER's apparent power rating. This is an

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[40] *Advancing Smart Inverter Integration in Utah: Final Report*, EPRI, Palo Alto, CA: 2019, 3002015334, at 1-1, https://pscdocs.utah.gov/electric/19docs/1903517/307937RMPAttach8-4-30-19.pdf.

[41] R. O'Connell, C. Volkmann, & P. Brucke, *Regulating Voltage: Recommendations for Smart Inverters,* at 9. GridLab, Sept. 12, 2019, http://gridlab.org/wp-content/uploads/2019/09/GridLab_Regulating-Voltage-report.pdf.

[42] The IEEE Standard defines Category B to be where the DER penetration is higher or where the DER power output is subject to frequent large variations.

autonomous response from the smart inverter, and it provides this voltage regulation service continuously during normal operating conditions.

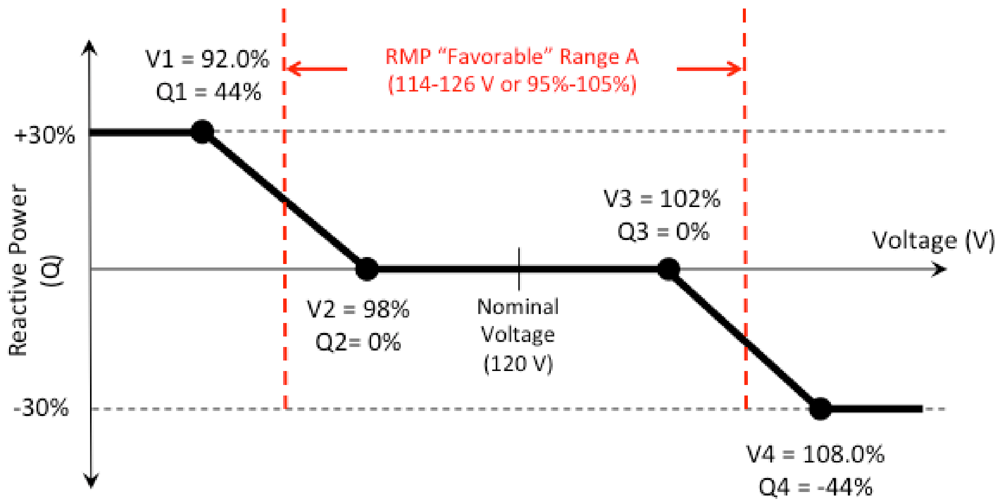

Figure 3 – IEEE 1547-2018 Default Volt-Var Settings for Category B DER[43]

Q. Can you further describe how volt-var works?

A. Yes. Consider a 10 kW CG system with a smart inverter that has an apparent power AC nameplate rating of 10 kVA. When the voltage at the inverter terminal is between 117.6 V and 122.4 V (or between 98% and 102% of the nominal voltage of 120 V), the CG system will produce only real power, up to a maximum of 10 kW. If the voltage at the inverter terminal rises above 122.4 V, the inverter begins absorbing reactive power. In the extreme case of the voltage rising to 129.6 V (108% of the nominal voltage of 120 V), the inverter would be absorbing 4.4 kVAR (44% of the nameplate rating), according to Figure 3.

[43] IEEE Standard 1547-2018, Table 8, p. 39.

Q. What does it mean to have volt-var with reactive power priority?

A. Reactive power priority means that the inverter must provide or absorb the required level of reactive power, curtailing real power as needed, due to the apparent power limits of the inverter.

Q. Has RMP established its required modes/settings for advanced inverters?

A. No. In response to a Vote Solar data request, RMP indicated that it has not determined the specific modes/settings it will require for advanced inverters.[44]

Q. Who will bear the cost of transitioning to advanced inverters?

A. Customers who have installed or will install CG will bear any additional cost for a smart or advanced inverter.

Q. What do you recommend?

A. Once smart inverters are fully available in the market,[45] RMP should take advantage of these new capabilities to defer or eliminate the need to invest in conventional voltage regulation equipment. RMP's policy and requirements for interconnecting DER to its distribution system is called Policy 138. I recommend that RMP update its interconnection Policy 138 to require volt-var mode with reactive power priority and the IEEE Standard Category B default settings for inverter-based CG.

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[44] Exhibit 4-CV, *Response to Vote Solar Data Request 6.1(7)*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 16, 2019).

[45] IEEE Standard 1547.1-2020, Test Procedures for Conformance with IEEE 1547-2018, was published on May 21, 2020. Updates to the associated UL 1741 test procedures are underway, and UL 1741 / 1547-2018 compliant inverters will be available in late 2020 or early 2021.

VII. RMP's Proposed CG Metering Fee is Arbitrary and Excessive

Q. What metering technologies has RMP used for CG customers?

A. The Company explains:

> Rocky Mountain Power completed the installation of a mobile automated meter reading (AMR) system in the state of Utah in 2010 …. The meters installed during, and subsequent to, the project are read once per month and provide energy and demand billing determinants for all residential and small commercial customers.
>
> Meters for large commercial and industrial customers, as well as meters where interval data is required (e.g. load research, Schedule 136, etc.) cannot be read by the mobile AMR solution currently deployed. These meters have not been replaced and continue to be read manually. These are the most expensive meters to read. The number of installations requiring interval data for billing purposes continues to increase dramatically and the need to find a cost effective solution for reading these meters is important to control costs.
>
> To address this need, in late 2017, the Company issued a request for proposal for the installation of an AMI network. This network is designed to avoid the high cost of manually reading large commercial, industrial and interval meters. The network will mitigate the associated increase in manpower as interval meter numbers continue to increase.
>
> In October 2018 the Company awarded a contract to Itron for their OpenWay Riva AMI solution … The installation of an Itron AMI system in Utah will provide the basic field area network required to automate approximately 18,000 manually read meters as well as all current and future meters associated with Schedule 136 (customer generators).[46]

[46] RMP, *An Investment Appraisal for Advanced Resiliency Management System (ARMS)*, at 3, Mar. 7, 2019, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/filings/docket-16-035-36/03-08-19_application_and_direct_testimony/05_Direct_Testimony_of_Rohit_P_Nair_-_Exhibit_RMP_RPN-1.pdf.

Q. How many AMI meters is RMP planning to install?

A. RMP plans to replace approximately 170,000 existing meters with AMI meters throughout its service territory by the end of 2022.[47] Additionally, the Company will install AMI meters for all new customer connections and meter replacements that occur after project completion.[48]

Q. How will the Company recover the costs of the AMI deployment?

A. In response to a data request, RMP states: "Costs will be recovered through the standard rate filings and processes."[49] This means that all RMP ratepayers will share the costs of the AMI deployment. RMP is requesting approval of $77.9 million of capital and $4.3 million of operations and maintenance costs for AMI in its current general rate case.[50]

Q. What metering fee is RMP proposing for new Schedule 137[51] CG customers?

A. RMP proposes a $160 metering fee for new Schedule 137 participants and explains:

> The Company is planning a partial deployment of advanced metering infrastructure ("AMI") in Utah in 2020 and 2021. For customers who have an AMI meter installed, the cost to re-program the customer's meter to begin recording delivered and exported energy will be substantially less than it was in the past. The Company estimates that it will expend about $20 to re-program the meter for a new customer-generator with AMI. New customer generators who do not have AMI will be equipped with an AMI meter that will be programmed to measure delivered and exported energy, which the Company estimates will cost $193.26 to install … (T)aking a weighted average of the $20 cost for customers with AMI and the $193.26 cost for customers without AMI by the anticipated customer counts with and

[47] Exhibit 5-CV, *Response to Vote Solar Data Request 11.5(9.2)*, RMP's Responses to Vote Solar 11th Set Data Requests (Apr. 17, 2020).
[48] *Id*.
[49] *Id*.
[50] RMP, *Direct Testimony of Curtis B. Mansfield*, Utah Public Service Commission, Docket No. 20-035-04, lines 586–87, May 8, 2020.
[51] Schedule 137 is RMP's proposed successor tariff to Schedule 136, its transition program for customer generators.

> without AMI after deployment at the end of 2021 yields an estimated metering cost of $160.34. The Company rounded this value down to $160 for its proposed fee.[52]

Q. Is RMP proposing the $160 fee for all new Schedule 137 customers?

A. Yes. RMP explains: "The Company is proposing to charge all new Schedule 137 customers a $160 customer generation metering fee, whether they have an AMI meter or not."[53]

Q. Does RMP currently charge customers for meter upgrades?

A. No. RMP does not currently charge customers for meter repair or upgrade services under any of RMP's electric service schedules in Utah.[54]

Q. Does RMP charge customers to reprogram meters under any of RMP's electric service schedules in Utah?

A. No.[55]

Q. After the initial AMI deployment in 2020-2021, will RMP charge a metering fee to customers who receive an AMI meter for new connections or meter replacements?

A. No.[56]

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[52] RMP, *Direct Testimony of Robert M. Meredith*, Feb. 3, 2020, lines 235–50.
[53] Exhibit 5-CV, *Response to Vote Solar Data Request 11.5(9.3)*, RMP's Responses to Vote Solar 11th Set Data Requests (Apr. 17, 2020).
[54] Exhibit 5-CV, *Response to Vote Solar Data Request 11.5(10.4)*, RMP's Responses to Vote Solar 11th Set Data Requests (Apr. 17, 2020).
[55] Exhibit 5-CV, *Response to Vote Solar Data Request 11.5(10.3)*, RMP's Responses to Vote Solar 11th Set Data Requests (Apr. 17, 2020).
[56] Exhibit 6-CV, *Response to Vote Solar Data Request 14.1(2)*, RMP's Responses to Vote Solar 14th Set Data Requests (June 24, 2020).

Q. What do you recommend?

A. RMP's proposed $160 meter fee for new Schedule 137 customers is arbitrary and inconsistent with what the Company charges non-CG customers who have a reprogrammed AMI meter or receive a new AMI meter. I recommend that the Commission reduce the proposed metering fee for new Schedule 137 customers from $160 to $0.

VIII. Conclusions and Summary of Recommendations

Q. What do you conclude?

A. I conclude that CG has a positive impact for RMP's customers by reducing T&D losses and contributing to the deferral or avoidance of T&D capital investment. The evidence in this proceeding does not support the alleged negative impacts from CG (i.e., high CG integration costs, wear-and-tear of distribution equipment). As CG penetrations increase across RMP's service territory, the Company can cost-effectively manage potential negative impacts by taking advantage of new smart inverter capabilities.

Q. Please provide a summary of your recommendations.

A. I recommend that:

1) The CG export credit include avoided energy losses from the transmission, distribution substation, primary line, and line transformer segments with cumulative avoided losses of 8.621%.

2) The CG export credit exclude any component related to alleged "wear-and-tear" on RMP's distribution equipment.

3) The CG export credit include the T&D capacity deferral value of at least 2.02 cents/kWh in 2021 dollars.

4) RMP take advantage of new smart inverter capabilities to defer or eliminate the need to invest in conventional voltage regulation equipment and update its interconnection Policy 138 to require volt-var mode with reactive power priority and the IEEE Standard Category B default settings for inverter-based CG.

5) The Commission reduce the proposed metering fee for new Schedule 137 customers from $160 to $0.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of July, 2020 a true and correct copy of the foregoing was served by email upon the following:

DIVISION OF PUBLIC UTILITIES:	
Chris Parker	chrisparker@utah.gov
William Powell	wpowell@utah.gov
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Erika Tedder	etedder@utah.gov
	dpudatarequest@utah.gov
OFFICE OF CONSUMER SERVICES:	
Alex Ware	aware@utah.gov
Philip Hayet	phayet@jkenn.com
Samuel Wyrobeck	swyrobeck@jkenn.com
Michele Beck	mbeck@utah.gov
Cheryl Murray	cmurray@utah.gov
Robert Moore	rmoore@agutah.gov
Victor Copeland	vcopeland@agutah.gov
Bela Vastag	bvastag@utah.gov
SALT LAKE CITY CORPORATION:	
Christopher Thomas	christopher.thomas@slcgov.com
Megan DePaulis	megan.depaulis@slcgov.com
UTAH SOLAR ENERGY ASSOCIATION:	
Amanda Smith	asmith@hollandhart.com
Ryan Evans	revans@utsolar.org
Engels J. Tejada	ejtejada@hollandhart.com
Chelsea J. Davis	cjdavis@hollandhart.com
WESTERN RESOURCE ADVOCATES:	
Nancy Kelly	nkelly@westernresources.org
Steven S. Michel	smichel@westernresources.org
Sophie Hayes	sophie.hayes@westernresources.org
UTAH CLEAN ENERGY:	
Sarah WrightKate BowmanHunter Holman	sarah@utahcleanenergy.org kate@utahcleanenergy.org hunter@utahcleanenergy.org

VOTE SOLAR:

Sachu ConstantineClaudine Custodio	sachu@votesolar.org
Jennifer M. Selendy	claudine@votesolar.org
Philippe Z. Selendy	jselendy@selendygay.com
Joshua Margolin	pselendy@selendygay.com
Margaret M. Siller	jmargolin@selendygay.com
	msiller@selendygay.com

AURIC SOLAR:

Elias Bishop	elias.bishop@auricsolar.com

ROCKY MOUNTAIN POWER:

Richard Garlish	Richard.garlish@pacificorp.com
Emily WegenerJana Saba	Emily.Wegener@pacificorp.com
Joelle Steward	jana.saba@pacificorp.com
	joelle.steward@pacificorp.com
	datarequest@pacificorp.com
	utahdockets@pacificorp.com

VIVINT SOLAR, INC.:

Stephan F. Mecham	sfmecham@gmail.com

/s/ Joshua S. Margolin