Exhibit 14-CV

17-035-61 Phase 2 Vote Solar Exhibit 14-CV 3-3-2020 Volkmann

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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August 23, 2019

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RE: UT Docket No. 17-035-61
Vote Solar 6th Set Data Request (1-24)

Please find enclosed Rocky Mountain Power's Responses to Vote Solar 6th Set Data Requests 6.1, 6.3, 6.6, 6.9, 6.11, 6.21 and 6.23-6.24. The remaining response will be provided separately as well as portions of Vote Solar 6.3 and 6.21. Provided are Attachments Vote Solar 6.1(2-3), 6.3 (1-3, 5-12), 6.6, 6.21 (2), 6.24 (1-2, 4-6) Also provided on a Confidential CD are Confidential Attachments Vote Solar 6.1 (1), 6.21 (1) and 6.24 (3).

If you have any questions, please call me at (801) 220-2823.

Sincerely,

___/s/___
Jana Saba
Manager, Regulation

Enclosures
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Vote Solar Data Request 6.1

Please describe RMP’s distribution planning process, including:

(1) Names of RMP’s Utah planning areas;

(2) Distribution substations and circuits in each planning area;

(3) Number of residential, commercial, and industrial customers in each planning area;

(4) Peak load in each planning area for each of the years 2014, 2015, 2016, 2017, and 2018;

(5) Forecasted peak load in each planning area for each of the years 2019, 2020, 2021, 2022, and 2023;

(6) Distribution planning criteria and design guidelines used by RMP to determine the need for new or upgraded circuits or substations;

(7) Voltage and reactive power modes and settings RMP does or will require for NEM inverters (e.g., constant unity power factor, volt/VAR with reactive power priority, etc.) and the rationale for this requirement;

(8) Steps in the distribution planning process, including timing and duration of each step;

(9) Organization(s) and fulltime-equivalent RMP employees and contractors involved in the process of distribution planning;

(10) Software tools utilized by RMP for forecasting, system modeling/mapping, power flow analysis, fault current analysis, or related distribution planning activities;

(11) RMP’s process for prioritizing distribution planning projects;

(12) RMP’s tools, methodology, and process for calculating and for publishing circuit hosting capacity;

(13) RMP’s tools, methodology, and process for determining circuit and substation peak loads;

(14) RMP’s tools, methodology, and process for determining circuit daytime minimum loads;

(15) RMP's tools, methodology, and process for load forecasting;

(16) RMP's net metering photovoltaic forecasting tools and methodology;

(17) RMP's forecasting tools and methodologies for other forms of distributed energy resources (e.g., non-solar distributed generation, energy efficiency, demand response, electric vehicles, energy storage, and combined heat and power);

(18) RMP's latest transmission and distribution map down to the distribution feeder and substation level and corresponding power flow cases that model RMP's latest transmission and distribution system at the highest level of detail available;

(19) A description of how RMP's distribution planning process is integrated with RMP's net metering interconnection process;

(20) A description of how RMP's distribution planning process is integrated with transmission planning;

(21) A description of how RMP's distribution planning process is integrated with RMP's Integrated Resource Plan and planning process; and

(22) A description of how RMP's distribution planning process is integrated with RMP's energy efficiency and demand response programs and program planning.

Response to Vote Solar Data Request 6.1

(1) Please refer to Confidential Attachment 6.1-1 for the Utah planning areas which provides 53 distribution planning studies, including distribution substation and circuits in each planning area. The Company generally updates the distribution planning every five years. Studies completed in 2019 will forecast years 2019 through 2023. Similarly, studies completed in 2015 will have forecast from 2016 through 2020. Customer-specific information and information unrelated to the data request has been redacted.

(2) Please refer to Confidential Attachment Vote Solar 6.1-1 which provides 53 distribution planning studies for Utah, including distribution substation and circuits in each planning area. The Company generally updates the distribution planning every five years. Studies completed in 2019 will forecast years 2019 through 2023. Similarly, studies completed in 2015 will have forecast from 2016 through 2020.

(3) The Company does not track this information.

(4) Please refer to the Company's response to subpart (2) above.

(5) Please refer to the Company's response to subpart (2) above.

(6) Please refer to Attachment Vote Solar 6.1-2.

(7) The Company plans to follow Institute of Electrical and Electronic Engineers (IEEE) 1547-2018 interconnection standards, however the Company has not yet decided the specific modes/settings required by net energy metering (NEM) customers.

(8) Please refer to Attachment Vote Solar 6.1-2.

(9) The Company has 17 full-time equivalent (FTE) employees and no contract employees involved in distribution planning for Utah. The Distribution Planning Group is involved in distribution planning for Utah.

(10) The Company uses Aspen Oneliner, CYME, Excel, FastMap, FAAR, GREATER, and Planning Peaks.

(11) Distribution planning projects are prioritized based on loading and/or voltage levels. When thermal overloads are projected, or voltage is projected to be outside of industry guidelines, projects are developed to resolve the anticipated issues.

(12) The Company does not track hosting capacity.

(13) The Company uses OSIsoft PI Datalink and ProcessBook tools to determine substation and circuit peak loading. For those substations and circuits with Supervisory Control and Data Acquisition (SCADA), data is stored in an OSIsoft PI database, then hourly averages are calculated utilizing the aforementioned tools. For substations and circuits without SCADA, drag hand reads are manually recorded then entered into the OSIsoft PI database as a single value. Peaks are calculated on an annual basis after the summer and winter peaks occur.

(14) The Company does not track minimum daytime loading.

(15) The Company performs a monthly jurisdictional forecast from which an hourly load forecast is developed. The hourly jurisdictional long-term forecast is then disaggregated into multiple geographic locations, or load pockets. The Company's jurisdictional long-term forecast incorporates a forecast of future private generation (PG) penetration assuming new market and incentive developments. Daytime minimum loads for each load pocket incorporates the Company's expectations for future PG.

(16) The Company's NEM photovoltaic (PV) forecast is conducted as part of the PV forecast completed within the Company's PG study. The PG study forecasts the adoption rate of PG at a state jurisdictional level. Fundamentally, the study is a customer adoption forecast based on payback acceptance from a customer perspective. The three primary variables are: (1) forecast changes to the technology costs, (2) the anticipated rate of improved performance from a technology, and (3) percentage of increase in electricity rates.

(17) Distribution planning load forecasts account for distributed energy resources (DER) through the offset of load in circuit peak load calculations.

(18) Please refer to Attachment Vote Solar 6.1-3 for the transmission network diagram and Confidential Attachment Vote Solar 6.1-1 for distribution maps. The distribution studies include information pertaining to substation and feeders.

(19) The Company performs PG interconnection studies as needed and required distribution improvements are specified in those studies. Distribution planning studies account for PG through the offset of load in circuit peak load calculations and load allocation in the distribution model. Please refer to Attachment Vote Solar 6.1-2.

(20) The Company's transmission planning and distribution planning process is integrated at the substation level. Transmission planners and distribution planners coordinate the calculation of substation transformer peak loads, load growth and forecasted block loads and transfers. Distribution planners recommend load transfers/distributions projects to defer substation capacity increases and transmission planners recommend substation and transmission projects based on the subsequent forecasts.

(21) Distribution system planning maintains distinct and separate requirements from integrated resource planning (IRP) however, distribution system projects inform the IRP. Loads greater than 1 megawatt (MW) are individually studied through a distribution system impact study (SIS) process and are also communicated to the IRP for inclusion in its load forecasting process.

(22) Distribution planning studies account for energy efficiency (EE) and demand response through the offset of load in circuit peak load calculations and load allocation in the distribution model. Please refer to Attachment Vote Solar 6.1-2 for an overview of the distribution planning process.

Confidential information is provided subject to Public Service Commission of Utah Rules 746-1-602 and 746-1-603.

Vote Solar Data Request 6.3

Please provide a spreadsheet containing the following for each of RMP's Utah distribution circuits:

(1) Circuit name and/or ID number;

(2) Substation name and/or ID number;

(3) Primary voltage (kV);

(4) Total overhead primary circuit miles;

(5) Total underground primary circuit miles;

(6) Number of residential, commercial, and industrial customers served;

(7) Circuit capacity (MW or MVA);

(8) PV hosting capacity (MW);

(9) Peak load (MW) for each of the years 2015, 2016, 2017, and 2018;

(10) Date and time of peak load for each of the years 2015, 2016, 2017, and 2018;

(11) Forecasted 2019 peak load (MW);

(12) Forecasted annual peak load growth 2019-2023 (%);

(13) Daytime minimum load (MW) for each of the years 2015, 2016, 2017, and 2018;

(14) Date and time of daytime minimum loads for each of the years of 2015, 2016, 2017, and 2018;

(15) Supervisory Control and Data Acquisition (SCADA)? (Y or N);

(16) Substation load tap changer (LTC)? (Y or N);

(17) LTC setpoint (120V base);

(18) Number of line regulators;

(19) Number of fixed line capacitors;

(20) Total fixed line capacitor compensation (kVAR);

(21) Number of switched line capacitors;

(22) Total switched line capacitor compensation (kVAR);

(23) Impedance to furthest load (Ohms);

(24) Number of all existing PV systems;

(25) Capacity of all existing PV systems (MWAC);

(26) Forecasted 2023 capacity of all PV systems (MWAC);

(27) Capacity of existing NEM PV (MWAC);

(28) Forecasted 2023 capacity of NEM PV (MWAC);

(29) Number of NEM customers with energy storage;

(30) Capacity of NEM-related energy storage (MW and MWh);

(31) Capacity of other energy storage (MW and MWh);

(32) Number of Electric Vehicles (EV) utilizing Level 2 chargers;

(33) Number of Level 3 EV chargers;

(34) Capacity of available demand response (MW); and

(35) Annual line losses (% and MWh).

Response to Vote Solar Data Request 6.3 (Note: Subparts 9, 10, 15, and 16 will be provided later.)

(1) Please refer to Attachment Vote Solar 6.3-1.

(2) Please refer to Attachment Vote Solar 6.3-1.

(3) Please refer to Attachment Vote Solar 6.3-1.

(4) Please refer to Attachment Vote Solar 6.3-2.

(5) Please refer to Attachment Vote Solar 6.3-2.

(6) Please refer to Attachment Vote Solar 6.3-3. As relates to distribution circuits, the Company does not separate total customers into customer classes and therefore that information is not available.

(7) Please refer to the Company's response to Vote Solar Data Request 6.1, specifically Confidential Attachment Vote Solar 6.1-1.

(8) The Company does not track this information.

(9)

(10)

(11) Please refer to the Company's response to Vote Solar Data Request 6.1, specifically Confidential Attachment Vote Solar 6.1-1.

(12) Please refer to the Company's response to Vote Solar Data Request 6.1, specifically Confidential Attachment Vote Solar 6.1-1.

(13) The Company does not track minimum daytime loading.

(14) The Company does not track minimum daytime loading.

(15)

(16)

(17) The LTC is typically set to 1.025 per unit (pu).

(18) Please refer to Attachment Vote Solar 6.3-5.

(19) Please refer to Attachment Vote Solar 6.3-6.

(20) Please refer to Attachment Vote Solar 6.3-6.

(21) Please refer to Attachment Vote Solar 6.3-6.

(22) Please refer to Attachment Vote Solar 6.3-6.

(23) The Company does not track this information.

(24) Please refer to Attachment Vote Solar 6.3-7.

(25) Please refer to Attachment Vote Solar 6.3-8.

(26) The Company does not forecast photovoltaic (PV) system capacity for each of the Company's Utah distribution circuits. However, based on the installed capacity of PV in Utah as of April 2019 and the most recent statewide baseline projection of PV system installations – the total forecasted 2023 capacity of all PV systems in Utah is 362.9 megawatts alternating current (MW_{AC}).

(27) Please refer to Attachment Vote Solar 6.3-9.

(28) The Company does not forecast PV system capacity for each of RMP's Utah distribution circuit. However, net energy metering (NEM) service is currently closed to new applications. As of July 2019, there were 92 Utah NEM applications open that could be interconnected in the future. Based on the installed capacity of NEM PV in Utah as of April 2019 and the open applications for NEM capacity that could be installed over the 2019 through 2023 timeframe – the maximum forecasted 2023 capacity of all Utah NEM PV is 231.3 MW_{AC}.

(29) Please refer to Attachment Vote Solar 6.3-10, specifically column B.

(30) Please refer to Attachment Vote Solar 6.3-10, specifically column C and D.

(31) Energy storage is tracked in different databases and each has different attributes and timeframes in which the data has been collected, thus there is some overlap in data between the two files. For example, Attachment Vote Solar 6.3-11 tracks battery storage with solar installations by circuit, and Attachment Vote Solar 6.3-12 includes information on kilowatt-hours (kWh).

(32) The Company objects to this request as the Company does not have a comprehensive database that identifies the number of electric vehicles (EV) utilizing level 2 chargers. Without waiving the objection, the Company has provided incentives for approximately 435 level 2 charging ports as of 2018. If every incentivized charging port was being used, there would be at least 435 level 2 charging ports.

(33) The Company objects to this request as the Company does not have a comprehensive database that identifies the number of level 3 / direct current (DC) Fast Chargers in the Company's service territory. Without waiving the objection, the Company has provided incentives for approximately 16 Level 3 / DC Fast Chargers as of 2018.

(34) In 2018, the maximum potential megawatt (MW) at generation available for demand response was 258 MW.

(35) The Company does not have the requested information.

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Vote Solar Data Request 6.3

Confidential information is provided subject to Public Service Commission of Utah Rules 746-1-602 and 746-1-603.

Vote Solar Data Request 6.6

Please provide a spreadsheet containing actual RMP Utah distribution capital and O&M expenditures for the years 2014, 2015, 2016, 2017, and 2018, together with forecasted expenditures for the years 2019, 2020, 2021, 2022, and 2023, for the following categories:

(1) System Reinforcement;

(2) System Compliance;

(3) New Residential Connections;

(4) New Commercial Connections;

(5) New Industrial Connections;

(6) Asset Replacement;

(7) Reliability; and

(8) Any others not already described.

Response to Vote Solar Data Request 6.6

Please refer to Attachment Vote Solar 6.6 for the actual Utah distribution capital expenditures for the historical years. Information related to the actual or forecast Rocky Mountain Power (RMP) distribution operations and maintenance (O&M) costs are not tracked in the categories listed above. However, actual O&M information is available by FERC Account and can be found by accessing the Company's annual results of operations (ROO) reports beginning at page 2.10 of each report:

2018:

https://pscdocs.utah.gov/electric/19docs/1903508/307939RMP2018RsltsofOps4-30-2019.pdf

2017:

https://pscdocs.utah.gov/electric/18docs/1803509/301675RMP2017ResOper4-30-2018.pdf

2016:

https://pscdocs.utah.gov/electric/17docs/1703515/293656RMP2016ResOper4-28-2017.pdf

2015:

https://pscdocs.utah.gov/electric/16docs/1603515/275491CvrLtrRMPResOper4-29-2016.pdf

2014:

https://pscdocs.utah.gov/electric/15docs/1503551/265944CvrtrRMPDec2014ResultsOper4-30-2015.pdf

Forecast RMP distribution O&M expenditures for the years 2019, 2020, 2021, 2022 and 2023 is not forecasted in the categories Vote Solar requested, but is available at an overall level. The forecast O&M expenditures and the requested information for forecasted capital expenditures for 2019, 2020, 2021, 2022, and 2023 is considered highly confidential and commercially sensitive. The Company requests special handling by contacting Jana Saba at (801) 220-2823 to make arrangements for review.

Vote Solar Data Request 6.9

Please explain what steps RMP has taken or plans to take to modify its interconnection requirements to incorporate IEEE Standard 1547-2018, including RMP's understanding of how deployment of advanced inverters compliant with IEEE Standard 1547-2018 may impact the operation of voltage regulation equipment.

Response to Vote Solar Data Request 6.9

Please refer to the Company's response to Vote Solar Data Request 6.1 subpart (7).

Vote Solar Data Request 6.11

From the transmission modeling performed with ABB's Planning and Risk or other similar model, provide a spreadsheet showing the following hourly input or output data from the preferred portfolio scenario for each year modeled:

(1) Hourly system lambda (marginal cost);

(2) LMP at each node within RMP's network ($/MWh);

(3) Committed capacity (MW);

(4) Minimum generation constraint from thermal units;

(5) Flexibility reserve (MW); and

(6) Regulation reserve (MW).

Response to Vote Solar Data Request 6.11

The Company objects to the data request on the basis that it does not have the requested information. Without waiving the objection, the Company responds as follows:

The 2019 Integrated Resource Plan (IRP) is not yet final nor published, and a preferred portfolio has not been identified to-date. In addition, ABB's (formerly VENTYX) Planning and Risk (PaR) model does not produce the requested data at an hourly level as configured to support the Company's long-term resource planning process. The Company expects to file its 2019 IRP for acknowledgement in its service territory in mid-October 2019.

Vote Solar Data Request 6.21

Please respond to the following questions relating to November 9, 2016 Direct Testimony of Douglas L. Marx in Docket No. 14-035-114:

(1) Provide the studies referenced in lines 57-60 that purport to show "increasing levels of rooftop solar can actually force the Company to increase the local distribution system including distribution transformers, secondary cables, and service conductors to handle the excess generation," and indicate where in the referenced studies the Company explains the need to "increase the local distribution system";

(2) Provide the actual costs incurred by RMP in each of the years 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 to "increase the local distribution system including distribution transformers, secondary cables, and service conductors to handle the excess generation" from rooftop solar;

(3) Provide all data, analysis, reports, or other evidence supporting the statement at lines 60-63 that "If customers . . . (become) net zero-electric energy customers, the Company will need to increase the size of the local distribution system to handle the reverse energy flow delivered to the grid by the customers";

(4) Please provide all data, analysis, reports, or other evidence supporting the statement at line 75 that the system may be sized up to 30% greater than normal;

(5) Provide all data, analysis, reports, or other evidence supporting the statement at lines 76-77 that "[i]n a few cases, the reverse power flow could approach 50% more as compared to the customers' peak load demand";

(6) Describe the "dead-line checking systems" referenced at line 88;

(7) Provide a copy of Mr. Marx's 2014 GRC testimony referenced at lines 90-91;

(8) Provide the underlying data for figure 1 on page 6;

(9) Clarify what explanation is referred to in Mr. Marx's testimony where he writes: "I have already explained that a net metering customer's peak utilization of the local distribution system . . . can be much higher than their summer peak load demand" at lines 101-103;

(10) Provide all data, analysis, and spreadsheets with formulas intact supporting the calculation of 11,558 kWh referenced at lines 111-112;

(11) Please provide all data, analysis, reports, or other evidence showing the distribution system upgrades, increased labor costs, and any other direct or

indirect costs that RMP would incur due to the 134% higher level of "energy managed" on behalf of the net-zero energy customer in the example referenced at lines 112-14;

(12) Provide the total customer call center costs directly attributable to net metering applications in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 124-27;

(13) Provide the total customer generation department costs directly attributable to net metering applications in 2014, 2015, 2016, 2017, 2018, and year-to date 2019 as discussed at lines 128-30;

(14) Provide the total engineering costs directly attributable to net metering applications in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 134-140.

(15) Provide the total costs for setting up the correct configurations within RMP's CSS for net metering customers in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 141-44;

(16) Provide the total operations department costs for inspections and net meter installations in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 145-49;

(17) Provide the total customer service group costs for creating virtual meters in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 149-51;

(18) Provide the total operations department costs for reviewing the CSS system and verifying billing determinants for NEM customers in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 151-53;

(19) VS6-21.19 Provide the total number of Level 1, Level 2, and Level 3 applications received by RMP in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 as discussed at lines 160-165; and

(20) Please provide all data, analysis, reports, or other evidence sufficient to explain the statement at line 223 that energy "must be stored" and clarify how RMP accomplishes this for residential NEM customers.

Response to Vote Solar Data Request 6.21 (Note: Subparts 2 and 19 will be provided later.)

The Company objects to the data request on the basis that it seeks information that is or may be dated and data that pertains to the subject of net metering and, therefore, is not relevant to the value of export credits and this docket. Without waiving the objection, the Company responds as follows:

(1) Please refer to Confidential Attachment Vote Solar 6.21-1.

(2)

(3) Please refer to the Company's response to subpart (1) above.

(4) Please refer to the Company's response to subpart (1) above.

(5) Please refer to the Company's response to subpart (1) above.

(6) A dead-line checking system detects voltage on the distribution system after a breaker opens. If voltage is detected, the breaker is stopped from closing to prevent any potential damage to customer equipment.

(7) Please refer to Attachment Vote Solar 6.21-2.

(8) Figure 1 was created for illustrative purposes only and the underlying data is no longer available.

(9) Please refer to the Company's responses to subpart (1) above and to the Company's response to Vote Solar Data Request 6.24 subpart (6).

(10) Please refer to the Company's response to subpart (1) above. The reference to 11,558 kWh is provided in cell Q18 of the "pvwatts_hourly" tab in the "Net Generation vs Peak Load v3 CONF.xlsx" file.

(11) Please refer to the Company's response to subpart (1) above.

(12) The requested information was not separately tracked prior to calendar year 2015.

2015	$82,992
2016	$198,008
2017	$322,050
2018	$296,963
2019 through June	$111,608.00

(13) Please refer to the table below:

Year	Utah Admin Costs
2014	$ 173,972.01
2015	$ 198,984.23
2016	$ 551,714.48
2017	$ 703,862.29
2018	$ 701,041.25
2019 through June	$ 271,300.87

(14) The Company does not track engineering costs directly attributable to net metering applications

(15) Please refer to the Company's response subpart (12) above which covers associated costs.

(16) The requested data is not available. Metering costs are not tracked by individual meter type or classification.

(17) Please refer to the Company's response to subpart (12) above which includes the associated costs.

(18) Please refer to the Company's response to subpart (12) above .

(19)

(20) This statement refers to a ledger accounting of excess energy that must be returned to the customer at some future date. The Company accomplishes this through the existing net metered schedule. Schedule 135, page 3, paragraph 2.A. states:

> Residential and Small Non-Residential Customer shall be credited for such net energy with a cumulative kilowatt-hour credit. The credit will be deducted from the customer's kilowatt-hour usage on the customer's next monthly bill thus offsetting the customer's next monthly bill at the full retail rate of the customer's rate schedule.

Confidential information is provided subject to Public Service Commission of Utah Rules 746-1-602 and 746-1-603.

Vote Solar Data Request 6.23

Please respond to the following requests relating to the July 25, 2017 Rebuttal Testimony of Douglas L. Marx in Docket No. 14-035-114:

(1) Explain the statement at lines 52-53 that "replacement energy for excess generation is subject to the full complement of system line losses which further reduces the value of any excess generation"; and

(2) Provide all data, analysis, reports, or other evidence supporting the statement at lines 228-29 that "as more NEM customers approach net-zero generation, local distribution losses will actually increase."

Response to Vote Solar Data Request 6.23

The Company objects to the data request on the basis that it seeks information that is or may be dated and potentially superseded by new information, and that pertains to the subject of net metering and, therefore, not relevant to the value of export credits and this docket. Without waiving the objection, the Company responds as follows:

(1) This would include line losses on services, secondary and primary conductors as well as any transformation losses.

(2) Please refer to the Company's response to Vote Solar Data Request 6.21 subpart (1).

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Vote Solar Data Request 6.24

Please respond to the following requests relating to the June 26, 2014 Rebuttal Testimony of Douglas L. Marx in Docket No. 13-035-184:

(1) Provide copies of each of the "Several studies (that) have shown . . . a high penetration of NEM will require infrastructure upgrades" referenced at lines 28-30;

(2) To the extent not already provided, provide details of the Northeast Substation expansion project referenced at lines 55-61, including scope of work for the expansion, capacity deficiency (MW), frequency of the deficiency (days per year), duration of the deficiency (hours of the day), additional capacity (MW) provided from the expansion, planned capital in 2010 (MW), and Northeast #16 circuit peak demand in 2018 (MW);

(3) Provide the source data with all formulas intact for the Study area chart referenced at lines 73-74 and in Exhibit A, and provide an explanation of RMP's calculation of 7%, including an explanation of the source data from which that calculation was performed;

(4) Provide the data in Appendices B and C to Exhibit A;

(5) Explain the statement at lines 74-75 that "[t]he seven percent contribution of solar generation would be reduced if served by similar generation remote to the study area due to additional power delivery losses";

(6) Provide the data with all formulas referenced at lines 77-80;

(7) Provide the number of NEM customers installing energy storage systems in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019;

(8) Provide all data, analysis, reports or other evidence supporting the statement at lines 98-100 that "customers who do install energy storage systems tend to not use them regularly";

(9) Provide all data, analysis, reports, or other evidence supporting the statement at lines 119-21 that "if all the panels were oriented for output at 5:00 p.m., the total annual energy production would decrease about 40-50 percent compared with south-facing panels";

(10) Provide all data, analysis, reports, or other evidence supporting the statement at lines 121-23 that "the maximum output level would drop nearly 70 percent due to the lower number of panels caused by shading and the reduced angle of incidence

from the sun";

(11) Indicate how many distribution transformers Pacific Power has had to replace to accommodate NEM customers due to the absence of a primary neutral connection;

(12) Provide the total cost for Pacific Power to replace distribution transformers to accommodate NEM customers;

(13) Explain whether RMP has distribution transformers without a primary neutral connection;

(14) Explain whether RMP has experienced one or more issues similar to the incident described at lines 141-53;

(15) Explain how Pacific Power was able to measure a rapid voltage fluctuation of 5.3 percent every 15 seconds, as discussed at lines 143-44, and where on the affected distribution circuit Pacific Power measured these fluctuations;

(16) Explain the reference to a "customer generation reclosing device" at lines 150-51;

(17) Provide all data, analysis, reports, or other evidence supporting the statement at lines 204-07 that "variability in customer generation output . . . will trigger increased automated operations in line equipment";

(18) Provide the increased number of annual automated operations of line equipment experienced by RMP due to NEM installations in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019;

(19) Provide all data, analysis, reports, or other evidence supporting the statement that variability in NEM output will "(reduce) life of the equipment";

(20) Provide the annual increase in RMP's line equipment maintenance costs due to the variable output of NEM installations in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019;

(21) Provide all data, analysis, reports, or other evidence supporting the statement at lines 207-210 that "voltage regulating devices can operate about 70 to 80 times on a cloudy day as compared to 12 to 19 operations during clear-sky days on systems with high levels of solar generation"; and

(22) Provide RMP's increased labor costs in 2014, 2015, 2016, 2017, 2018, and year-to-date 2019 to implement new standards and study the distribution system to assure that customer generation can be accommodated, as discussed at lines 273-74.

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Response to Vote Solar Data Request 6.24

The Company objects to the data request on the basis that it seeks information that is or may be dated and potentially superseded by new information, and that pertains to the subject of net metering and, therefore, not relevant to the value of export credits and this docket. Without waiving the objection, the Company responds as follows:

(1) Please refer to the Company's response to Vote Solar Data Request 6.21 subpart (1), and to the Company's responses to subparts (3) and (10) below.

(2) Please refer to Attachment Vote Solar 6.24-1 and Attachment Vote Solar 6.24-2. The peak demand in 2010 was 3.03 megavolt ampere (MVA), and in 2018 it was 2.865 MVA.

(3) Please refer to Confidential Attachment Vote Solar 6.24-3.

(4) Please refer to the Company's response to subpart (1) above.

(5) Line losses from remote generation would reduce the amount of energy actually delivered.

(6) Please refer to Attachment Vote Solar 6.24-4.

(7) Please refer to the table provided below:

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**Year to date 2019**
Number	0	1	0	4	80	44

(8) Residential customers in Rocky Mountain Power's (RMP) service territory typically install energy storage systems for emergency back-up purposes. Currently demand and/or time of use (TOU) pricing is not available under the net energy metering (NEM) tariff for residential customers. Due to these reasons, the Company does not think customers have a financial incentive to utilize energy storage systems regularly.

(9) Please refer to the Rebuttal Testimony of Company witness, Douglas L. Marx in Docket 13-035-184, specifically Exhibit A and Attachment Vote Solar 6.24-5.

(10) Please refer to the Company's response to subpart (9) above.

(11) From 2015 through June 2019, there has been one instance where the Company has had to replace or upgrade a transformer to accommodate NEM customers due to the absence of a primary neutral connection.

(12) From 2015 through June 2019, the total cost for the Company to replace distribution transformers to accommodate NEM customers is $137,000.

(13) Any distribution transformer connected wye-delta will not have a primary neutral connection.

(14) The Company has not experienced the same issue.

(15) A Metrosonics PA9 Power Quality Analyzer was installed on the secondary service at the site where the customer generation units are installed.

(16) The customer generation reclosing device referenced was a Cooper NOVA Form 6 recloser.

(17) Please refer to the Company's response to subpart (9) above.

(18) The Company does not track this information.

(19) Please refer to Attachment Vote Solar 6.24-6.

(20) The Company does not track this information.

(21) Please refer to the Company's response to subpart (9) above.

(22) Please refer to the Company's response to Vote Solar Data Request 6.8 subpart (3).

Confidential information is provided subject to Public Service Commission of Utah Rules 746-1-602 and 746-1-603.