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–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF APPLICATION OF ROCKY MOUNTAIN POWER TO ESTABLISH EXPORT CREDITS FOR CUSTOMER GENERATED ELECTRICITY	))))))))	DOCKET NO. 17-035-61 Exhibit No. DPU 1.0 DIR Phase II

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

ROBERT A. DAVIS

March 3, 2020

REDACTED

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I. INTRODUCTION

Q: Please state your name and occupation.

A: My name is Robert A. Davis. I am employed as a Utility Technical Consultant at the Utah Department of Commerce-Division of Public Utilities ("Division").

Q: What is your business address?

A: My business address is 160 East 300 South, Heber Wells Building-4th Floor, Salt Lake City, Utah, 84111.

Q: On whose behalf are you testifying?

A: The Division.

Q: Do you have any exhibits that you would like to add to the record?

A: Yes. DPU Exhibit 1.1_Davis Dir_PH II_Residential and Non-Residential Compiled Graphs CONF_3-3-20, and DPU Exhibit 1.2_Davis Dir_PH II_S&P Global Market Pricing_3-3-20.

Q: Does the Division have any other witnesses for this proceeding?

A: Yes. Dr. Abdinasir Abdulle discusses Rocky Mountain Power's (RMP) avoided cost method and assumptions for determination of the proposed rates in his testimony.

Q: Please summarize your educational and professional experience.

A: I earned a Master's Degree in Business Administration with Master's Certificates in Finance and Economics from Westminster College in May of 2005. I have attended the

NARUC Rate School, MSU/IPU Advanced Regulatory Studies Program, and Depreciation Fundamentals by the Society of Depreciation Professionals. I am a member of the LBNL/WIEB Technical Advisory Committee for Utility Rate Design, a member of the NREL DER-PV Ratepayer Impact Tool Advisory Committee, and have attended several regulatory seminars and conferences. I have been employed by the Division since May of 2012.

Q: Please describe your current position responsibilities.

A: I am a Utility Technical Consultant. My responsibilities include financial, economic, and accounting analysis of regulated utility matters with an emphasis towards renewable energy and storage.

Q: Have you previously testified before this Commission?

A: Yes. I have testified before the Public Service Commission of Utah ("Commission") on several occasions.

II. PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony in Phase Two of this proceeding?

A: My testimony summarizes the Division's analysis of Rocky Mountain Power's ("RMP") Load Research Study ("LRS"). Secondly, I offer the Division's conclusions and recommendation for Rocky Mountain Power's ("RMP") proposed Schedule 137 export credit rates for customer generated electricity.

Q: Can you offer a brief summary of your conclusions?

A: Yes. The Division has analyzed the monthly interval data from RMP's LRS, which began in January of 2019 and provided monthly data through December of 2019. The Division focused on the Commission's Order[1] in Phase One to determine how much and when customer generation is exported to the grid. The Division's LRS analysis informs its conclusions and recommendations in general support of RMP's Schedule 137 proposal to establish rates for customer generation exports.

III. RECOMMENDATION

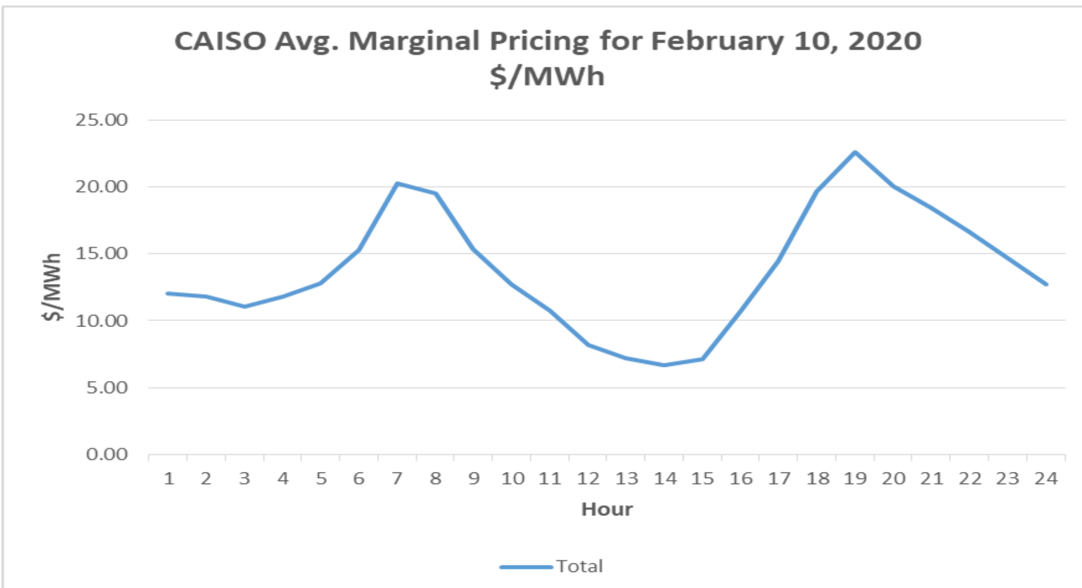
The Division generally finds RMP's proposal reasonable as it applies a method that better aligns export credits to avoided costs while giving RMP an opportunity to recover fixed system costs without imposing additional costs on other users. However, the Division needs more time to analyze RMP's avoided cost pricing assumptions and billing impacts to solar generation customers before recommending approval to the Commission. The pricing assumptions for Schedule 38 in Docket No. 19-035-18, which informs Schedule No. 37 that RMP relies on for this docket, are under review at the present time. Furthermore, other parties may offer useful measures of costs and values that ought to be considered.

Illustration 1 is a snapshot of the California Independent System Operator's ("CAISO") location marginal pricing ("LMP") for February 10, 2020.[2] Although this is

[1] See Phase I Report and Order, Docket No. 17-035-61, May 21, 2018, https://pscdocs.utah.gov/electric/17docs/1703561/3022941703561pIo5-21-2018.pdf.
[2] See PRICES tab, Locational Marginal Prices, February 10, 2020, at http://oasis.caiso.com/mrioasis/logon.do.

only a snapshot on a single day, it provides some evidence that RMP's proposal is within reason. These power prices appear to be similar in magnitude as RMP's proposed prices, suggesting the value of exported generation from customers is at least near the prices RMP proposes. I provide more explanation of market pricing comparisons later in my testimony.

Illustration 1



IV. DOCKET BACKGROUND

Q: Can you provide a brief history of this docket?

A: Yes. On August 29, 2014, the Commission issued its Report and Order in Docket No. 13-035-184 declining to implement PacifiCorp's proposed net metering facilities charge.[3] On the same day, the Commission issued its Notice of Technical Conference opening

[3] See Commission Order, Docket No. 13-035-184, August 29, 2014, pg. 71 ¶ 7, https://pscdocs.utah.gov/electric/13docs/13035184/26006513035184rao.pdf.

Docket No. 14-035-114.[4] On September 29, 2017, the Commission issued its order approving the parties' settlement stipulation for Docket No. 14-035-114.[5] The record for Docket No. 14-035-114 is voluminous and will not be repeated here.[6] The settlement terms grandfathered current net metering customers (Schedule 135) as of November 15, 2017 until December 31, 2036 and established Schedule No. 136. The Schedule 136 Transition Customer Program commenced on November 15, 2017, and offers an interim rate to customers that install solar until such time that a rate is determined at the conclusion of this docket.[7]

The settlement terms required RMP to file an application with the Commission requesting a docket to determine an export credit rate for customer generation. On December 4, 2017, the Commission issued its Notice of Scheduling Conference opening Docket No. 17-035-61. The parties agreed to bifurcate the docket into two phases during the first scheduling conference held on December 11, 2017. The first phase required RMP to gather and provide the LRS information. The second phase uses the LRS data to inform creation of an export credit rate for customer generation.[8]

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[4] See Commission Notice of Technical Conference, August 29, 2014, https://pscdocs.utah.gov/electric/14docs/14035114/26007114035114notc.pdf.

[5] See Commission Order Approving Settlement Stipulation, Docket No. 14-035-114, September 29, 2017, https://pscdocs.utah.gov/electric/14docs/14035114/297036140351140ass9-29-2017.pdf.

[6] See https://psc.utah.gov/2016/06/20/docket-no-14-035-114-2/.

[7] Current net metered customers under Schedule 135 remain on the Net Metering Program (i.e., kWh for kWh) until the end of 2036. Transition Customers under Schedule 136 are grandfathered until 2032. New customers and grandfathered customers at the conclusion of their respective grandfathered periods, will receive compensation at the new export credit rate.

[8] Commission Phase I and Phase II Scheduling Orders, December 12, 2107 and January 16, 2018, respectively, https://pscdocs.utah.gov/electric/17docs/1703561/2984151703561posoanohanoptsc12-12-2017.pdf, and https://pscdocs.utah.gov/electric/17docs/1703561/2991841703561ptsonopwhanoh1-16-2018.pdf.

V. LOAD RESEARCH STUDY CONCLUSIONS

Q: Can you summarize the Load Research Study plan?

A: Yes. Distributed generation technology operated by most private generation customers is primarily solar photovoltaic ("PV"). The proposed LRS for this docket exclusively studies PV generation. Like other distributed generation technologies, PV has its own characteristics. PV typically starts producing energy in the morning as the sun begins to rise, peaks mid-day, and ramps down in the early evening hours as the sun sets. PV generation is variable with weather, heat, orientation, and terrestrial attributes. The effects of these attributes ultimately determine the overall output and timing of customer owned PV generation throughout the day.

The LRS provides raw 15-minute delivery, production, and export interval data for every day over twelve months from samples of Utah residential and non-residential solar customers. This data represents how much energy the sample customers are consuming from the grid, producing from their own generation, and exporting back to the grid. From the data, the customers' hypothetical load profiles without generation can be mathematically derived.

Q: Can you describe the LRS design method?

Yes. The scope of work for the LRS calls for the design of a sample including residential and non-residential solar customers to determine when and how much energy is exported to the grid[9] over a one-year time horizon regardless of weather, orientation, or other attributes associated with customer generation.

RMP randomly selected customers from Schedule 135 and Schedule 136 following a four-stratification schema based on name plate capacity and installed generation meters. RMP selected the entire Schedule 136 population for deliveries and exports.

These stratified production meters, along with profile meters that capture deliveries and exports, have provided data in 15-minute intervals over every day for twelve months beginning January 2019. All Schedule 136 Transition Program customers have profile meters that provide delivery and export data in 15-minute intervals captured over the same period. RMP's LRS design has a precision of +/- 10 percent at the 95 percent confidence level, which exceeds industry standards.[10] The Division concludes that the LRS data provides valuable data that describes how much and when exported energy is pushed to the grid to help inform the design of a reasonable export credit rate.

Q: Did the Commission approve RMP's LRS plan?

[9] See RMP, Response to Joint Petition for Review or Rehearing, July 5, 2018, pg. 6, Section B, *"In determining just and reasonable rates for exported electricity, the plain language of Utah Code Ann. § 54-15-105.1(1) limits the scope of the consideration to actual costs incurred and benefits accrued by the Company and its other customers,"* https://pscdocs.utah.gov/electric/17docs/1703561/303310RMPRespJntPetRevRehear7-5-2018.pdf.

[10] The Public Utilities Regulatory Policy Act (PURPA) defines a minimum *Accuracy Level* of +/- 10 percent at the 90 percent confidence level. 1992 Code of Federal Regulations (CFR), Title 18, Chapter 1, Subchapter K, Part 290.403, Subpart B.

A: Yes. The Commission approved the load research study ("LRS") plan in its Phase One Report and Order of this docket. RMP's original design was contested in Phase One by some of the parties. The Commission ordered RMP to revise its study, which RMP did, to meet certain criteria.[11]

The Commission ordered RMP to select new samples from residential and commercial customers that either give each member of the class an equal chance of being selected, or each member of the separate strata an equal chance of being selected. Second, the Commission ordered RMP to increase the sample size to accommodate the separate study of residential and commercial customers. Finally, the Commission ordered RMP to collect export, import, and production data from the existing 36 Schedule 135 customers participating in the LRS.[12]

Q: How did RMP report the results of the LRS?

A: RMP compiled the LRS raw data into five separate files: (1) LRS New Sample Residential; (2) LRS New Sample Non Residential; (3) Original 36 NEM; (4) Schedule 136 Residential and Non-Residential Exports; and (5) Schedule 136 Residential and Non-Residential Deliveries. The LRS New Sample and Original 36 NEM (Net Metering) for residential and non-residential are sampled through strata while the Schedule 136

[11] See Commission Phase I Order, Docket No. 17-035-61, May 21, 2018, pg. 19-20. https://pscdocs.utah.gov/electric/17docs/1703561/3022941703561pIo5-21-2018.pdf.
[12] See RMP, Response to Joint Petition for Review or Rehearing, July 5, 2018, pg. 7, Section B, 1-2, https://pscdocs.utah.gov/electric/17docs/1703561/303310RMPRespJntPetRevRehear7-5-2018.pdf.

residential and non-residential delivery and export data represents the full population of customers.

Q: Did the LRS provide robust results?

A: Yes. The LRS design called for a sample size of forty-five residential and sixty non-residential customers to participate in the study, plus the original thirty-six NEM customers.

Over the study period, raw data at the designed sample size, or very near the designed sample size, was collected from residential and non-residential LRS customers. Export and delivery data was collected for the full population of residential and non-residential taking service under Schedule 136 over the study period. The full population data provided [redacted] and [redacted] samples of 15-minute interval data, respectively, by the end of the study period.

Q: Did you find any errors in the raw data?

A: Yes. Over the course of the study period, I noticed two reoccurring problems. First, some IDs (meters) missed readings at various intervals on random days throughout each month of the study. There was no pattern in which meter, intervals, or days failed to produce readings. Random interval data was missing from the delivery, export, or production registers, and sometimes all three. Second, data from the delivery and export registers of an ID might be available but without production data. Conversely, data might also be present for production but not export or delivery.

Q: How did you address the issue of missing data?

A: I used Excel functions to match customer IDs for deliveries, exports, and production for the entire sample set. In the case where data appeared for deliveries and exports but not production, I removed the deliveries and exports so delivery, export, and production data were valid for each customer. I used the same technique when production data was available but no deliveries or exports. The missing data intervals were relatively infrequent and did not appear to have any significant effect on the results.

Q: Is it your opinion that the study provides pertinent detail even with the missing data?

A: Yes. Over the course of the study period, the plotted data provides load shapes that demonstrate when the solar is producing in relation to System and Utah load shapes as illustrated later in my testimony.

Q: Please provide a summary of the Division conclusions of the LRS?

A: The Division recognizes the data from the LRS might produce numerous results depending on how it is analyzed. The Division's analysis centers around two areas of study. First, we analyzed the raw data to produce graphs for all the sample sets for each month to illustrate the timing and quantity of exports. The Division's graphs illustrate delivery, production, and full requirement based on RMP's full requirement formula over 15-minute intervals for every day of each of the twelve months in the study. Full requirement is determined mathematically from the delivery, export, and production data by the following formula:

Full Requirement = Deliveries + (Production less Exports)[13]

The Division's graphs also illustrate the timing of the total sample exports of customer generation in relation to Utah peak load and System peak load. The Division has not drawn any conclusions at the time of this filing in its analysis of the relationship between Schedule 136 deliveries for residential and non-residential customers.

Second, the Division's analysis explores the variability of export generation effects on the system over the study period. Although inconclusive at the time of this filing, the data shows an increase in variability to the grid as a result of customer generation export during certain times of the year. It makes sense that RMP needs to design its system around this variability to maintain reliability. It is a reasonable assumption that additional variability has the potential to wear out certain distribution equipment[14] at a faster rate than otherwise would occur. The Division cannot quantify how the variability impacts the system at this time but brings up the point as an issue needing further research to study how customer generation exports might affect the system and its reliability, and potentially result in a cost to all ratepayers at some point in time.[15]

Another way to analyze the variability issue, mainly the wear-and-tear on the system, is how the system responds should the solar production go away for whatever

[13] RMP, Direct testimony of Kenneth Lee Elder Jr, February 15, 2018, Figure 1, line 146, page 7.
[14] For example: regulators, transformer taps, etc. 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.
[15] The Division has not requested any studies from RMP regarding wear-and-tear on its distribution system at this time.

reason over a short time on feeders with higher solar penetrations. The Division's illustrations for Schedule 136 residential and non-residential, full population, exports demonstrate this assertion.

Q: Do you have any exhibits to illustrate your claims?

A: Yes. The following exhibits illustrate the variability, timing, and quantity of exports for June and January of the study period. For brevity, I chose a full sample set for the month of June during peak solar production times and a single residential sample for January for illustrative purposes. Sample sets for all the months during the study period including temperature and precipitation totals, System and Utah load information, and other export data, can be found in confidential Appendix A at the end of my testimony.[16]

Illustration 2, LRS New Sample Residential, offers the profile for June, 2019. June illustrates the timing, amount, and variability that the system sees during one of the summer months in kilowatts ("kW"). The data used to compile the graph is the mean of the daily average (the interval data for each meter is averaged daily and then the days of the month averaged to arrive at the average export, deliveries, and production for all meters at each interval for the month). Full requirement is determined using the above formula for each interval and is compiled in the same manner by finding the mean of the daily average for deliveries, plus the net of exports less production. The third standard deviation is determined from the daily averages for each interval. The third standard

[16] See 17-035-61_DPU Exhibit 1.1_Davis Dir_PH II_Residential and Non-Residential Compiled Graphs CONF_3-3-20.

deviation was chosen as likely the worst case scenario the utility would have to design its system around for reliability. The other months are constructed in the same manner.

Illustration 2 shows that solar production begins around [redacted] and ends at [redacted] As production increases and deliveries begin to drop off, exports begin around [redacted] and continue [redacted] The full requirement line shows an approximation of normal demand without solar. Finally, the 3rd standard deviation demonstrates the variability the system sees as a result of solar production and load.

Illustration 2

[redacted]

The Division cannot determine at this time how much of the variability is common to the normal load or as a result of the solar production (i.e., weather, orientation, etc.).[17] The variability may be the result of both. The Division is researching

[17] Appendix A contains temperature and precipitation for each month of the study. See https://www.weather.gov/slc/CliPlot.

the variability and will draw its conclusions in the next round of testimony. 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. I discuss this in more detail later in my testimony.

Illustration 3 shows the total exports for the month of June by hour of the day. This graph illustrates the sum of the daily sum exports (the interval data for each meter is summed daily and then the days summed to arrive at the total export for all meters at each interval for the month). The sum of the daily sum portrays a better representation of what the system impact is for the interval timing and amount of exports from the LRS Schedule 136 residential customer sample.

Illustration 3

[redacted]

Illustrations 4 through 7 illustrate the delivery, export, production, and total export profiles for the LRS Schedule 136 Non-Residential, and Original 36 NEM samples, respectively, for June, 2019.

Illustration 4

[redacted]

Illustration 5

[redacted]

Illustration 6

[redacted]

Illustration 7

[redacted]

Graphing the exports for the Schedule 136 residential and non-residential full population in a similar way is challenging due to the amount of data. The residential data, as of December, comprises over [redacted] lines of 15-minute interval data. The non-residential produces just over [redacted] lines of data. The Division uses a different method to illustrate the export amount and timing due to the large amount of data compared to the prior illustrations by plotting the exports by daily time points. The analysis first finds the mean of the daily average as before but then plots those time points for each day of the month. Illustrations 8 through 11 illustrate the residential and non-residential time points and total exports, respectively.

Illustration 8

[redacted]

Illustration 9

[redacted]

Illustration 10

[redacted]

Illustration 11

[redacted]

The significance of Illustrations 8-11 is that the system has to respond accordingly in a timely manner should the solar generation drop off and return for whatever reason to keep the grid reliable.

Q: Have you prepared graphs that illustrate the relationship of the samples to Utah and System load?

A: Yes. Illustration 12 plots the System and Utah load, evening peaks, and the total sample exports from the LRS for June, 2019.

Illustration 12

[redacted]

Illustrations 13 and 14 show load shapes for residential customers and the relationship of exports to System and Utah load with the addition of morning peaks for January, 2019.

Illustration 13

[redacted]

Illustration 14

[redacted]

Q: Do you have any data that shows the total solar exports for Utah during 2019?

A: Yes. RMP does not track customer generation total exports on an hourly basis as depicted in Illustrations 13 and 14. RMP's response to Division Data Request 7.1[18] provides data on a monthly basis for total exports in Utah for the period of January 2019 through December 2019 shown in Table 15.

Table 15

[redacted]

Q: Please explain the difference between the exported amounts shown in Illustrations 13, 14, and those in Table 15?

A: Illustrations 13 and 14 show total exports on an interval basis for the LRS whereas Table 15 shows monthly exports for all solar generation in Utah. The System and Utah peak load data[19] in Illustrations 13 and 14 are sorted to depict the max load hour for all days in the given month. The Utah total LRS exports is the sum of the daily sums for each

[18] RMP response to Division Data Request 7.1, Attachment DPU 7.1, February 10, 2020.
[19] RMP response to Division Data Request 6.1 and 6.2, Attachment DPU 6.1-1 CONF

interval and then converted to an hourly total by taking the max of the four intervals during each hour over the 24 hour period.

Q: What conclusions can you draw from your analysis of the LRS data?

A: The Division concludes that the current level of customer solar generation exports (roughly [redacted]) offset little if any of the System or Utah morning and evening peak load at any time of the year. The graphs illustrate that solar reduces deliveries during the non-peak daytime hours and pushes excess generation to the grid as virtual storage where it is ultimately used as bill credits on solar customers' bills for both 135 and 136 customers. At the current penetration levels and timing of customer generation compared to Utah coincident load and System load of roughly [redacted] and [redacted],[20] respectively, demonstrates that customer generation provides limited benefits during peak periods.

However, the amount and timing of customer generation may prove to be useful in smaller, real-time balancing applications rather than consistent load for which otherwise planned purchases or generation can be avoided.

Q: What other observations have you made from your LRS analysis that raises Division concerns?

A: The bi-directional flow of customer generation raises questions about the wear-and-tear on the system to reliably meet load. PacifiCorp's integrated resource plan ("IRP") studies

[20] RMP response to Division Data Request DPU 6.1-1 5th Supplemental CONF.

customer generation (Private Generation) as a reduction to load.[21] While load is often reduced during solar generation hours, the relationship with the grid is more complex than a simple load reduction. Customer generation, even at the relatively small current penetration level, is not simply a reduction of load like demand side management ("DSM") because it uses the system differently and should be modeled as such.

Q: Please explain what you mean customer generation uses the system differently.

A: 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[22] low.

Whereas DSM reduces load and therefore costs over a 24/7 period throughout the year, solar pushes to the grid when production exceeds usage and pulls from the grid when usage exceeds production. It fluctuates throughout the 24/7 period depending on other attributes.

Q: Did you draw any conclusions from the LRS?

A: Yes. The Division analyzed the standard deviation of the mean of daily averages for all the sample sets and Schedule 136 full population. Although inconclusive at this filing

[21] PacifiCorp's 2019 Integrated Resource Plan, Volume 1, Chapter 5, Load and Resource Balance, Private Generation, pg. 107.

[22] Capacity contribution is defined as "The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. PacifiCorp 2019 IRP, Volume 1, Chapter 7, New Resources, Wind and Solar Resources, at page 177.

because the Division has not completed its analysis of the standard deviation of non-solar customer usage patterns, the LRS samples do show an increase in standard deviation during solar production during certain times of the year, mainly the summer months. This is an area the Division considers a need for further research and analysis as customer generation increases.

Q: If further analysis reveals that the variability is a result of solar generation, how might the variability impact the system?

A: 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.

Q: Is it your opinion that this variability is currently an issue on RMP's system?

A: 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. The Commission may choose to direct RMP to study this issue and file its conclusions in the future.

Q: Is the Division concerned with reliability issues at the current penetration levels?

A: Not at the current penetration levels. However, if customer generation penetration levels increase, it is intuitive that the distribution system components will likely have to make adjustments more frequently to maintain system reliability. This means that system components might wear out faster than normal, leading to increased costs to all rate payers.

The National Renewable Energy Laboratory studies distributed generation to gain an understanding of bi-directional power flows on traditional distribution systems. When 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. On a circuit with no DGPV present, the voltage along the feeder decreases as distance from the substation increases. The voltage at the distribution substation is normally kept high, and tap-changing transformers and/or switched capacitor banks are used to further compensate for the voltage drop.[23]

Q: Can you summarize your conclusions from the Division's analysis of the LRS?

A: Yes. All things considered, customer solar generation at the current penetration level offers little if any offset to system generation costs, especially at the peak times of the day. Additionally, customer solar generation seems to inject an unknown amount of variability to the system, at least at certain times of the year. The LRS conclusions

[23] National Renewable Energy Laboratory, Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System, September 2014, Appendix B. DGPV Impacts on Distribution Systems-Voltage Control, pg. 65-66, https://www.nrel.gov/docs/fy14osti/62447.pdf.

provide evidence of how much and when customer generation hits the grid as ordered by the Commission. The next step is to use that evidence to inform the design of a reasonable export credit rate.

VI. EXPORT CREDIT RATE

Q: Has the Division calculated a rate for export credits?

A: No. The Division supports an avoided cost method that aligns system costs and benefits to the timing and quantity of customer generation exports that are sent to the grid. The necessary inputs and modeling needed to determine such a rate requires a collaborative effort between RMP and parties. However, RMP's proposal does appear to be in the range of the rough magnitude of the value customer generation exports provide the system, based on our review of some market data.

Q: Have you reviewed RMP's proposed Schedule No. 137 rate structure for customer generation export credit?

A: Yes. RMP is proposing a new tariff, Schedule 137, which offers a variable export rate to behind-the-meter ("BTM") generation customers based on the time of day and winter/summer seasons including an adjustment for line losses and integration costs. RMP proposes that Schedule 137 become effective January 1, 2021. RMP also proposes a $150 non-refundable application fee and a $160 customer generation meter fee.

Q: Does the Division agree that RMP's proposed Schedule 137 is reasonable and in the public interest?

A: The Division generally supports RMP's approach to proposed Schedule 137 and export credit pricing at this time. The Division's conclusions from the LRS illustrate that customers with BTM generation use the system differently. More to the point, the LRS shows that customer generation exports or offsetting of deliveries have minimal impact during System or Utah peak load periods at any time of the year. At the time of this filing, the Division has not fully vetted all of RMP's proposal as discussed later in my testimony, especially with regard to contemporaneous market prices for similar volumes of energy at similar times. It does appear to be close to the value of the generation provided; it is fairly clear that it is nearer an actual value than the existing transition rate.

RMP's proposed rate schedule incents customer generators to use their own generation during times of the day that benefit them by offsetting higher delivered energy rates versus export rates, while providing system cost avoidance that RMP would otherwise incur to meet load. RMP's proposed rate schedule also rewards customer generators at a higher rate when their exports likely avoid higher peak load costs in the mornings and evenings. This rate structure also incents customers to install storage that would likely offset peak load shoulders. In other words, the proposal's structure seems to generally and properly align credit amounts with system value.

Q: Does RMP's rate schedule eliminate the virtual storage issue associated with net billing schemes?

A: Virtual storage is necessary for net billing schemes to work. Customer generation exports are recorded as credits during daytime hours over the course of a month when residential loads are low. The utility uses the exports to meet load and potentially curtail its own fleet generation.

The exports, as illustrated by the graphs, occur during the time of day when the utility's costs to produce energy are lower compared to the costs to produce energy at peak times. Thus, there is a discrepancy between pricing of when the utility receives exports and the energy it delivers.

When residential and non-residential customers use their solar production during daytime hours to meet their loads, the virtual storage issue subsides, and customer bills reflect the offset of delivered energy costs on a more unitary basis. Illustration 16 depicts Schedule 136 residential full-population deliveries for the month of June. The deliveries approach zero during the peak solar production time of the day. The Division's analysis of the timing relationship between customer production, consumption, and export versus deliveries is not conclusive at this time.

Illustration 16

[redacted]

Q: Can you discuss the variance between the current rate and RMP's proposed rate design?

A: Yes. The current rates under Schedule 136[24] range between $0.092 for residential and $0.034 for Schedule 6 customers. These rates are the result of a stipulation between parties in Docket No. 14-035-114. If approved, the proposed rates treat all customer exports in a similar manner. The value of different customer exports to the system seems unlikely to vary much. The overall proposed rate[25] is $0.015261, an eighty-three percent reduction for residential customers.

[24] See https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/136_Transition_Program_for_Customer_Generators.pdf.

[25] RMP, Meredith Direct Testimony, Docket No. 17-035-61, Exhibit RMP_(RMM-1), Sheet No. 137.3, June-September, $0.026293 per kWh for all On-Peak, $0.017080 per kWh for all Off-Peak, October-May, $0.02409 per kWh for all On-Peak, $0.013247 per kWh for all Off-Peak.

Although such a large reduction might be cause for invoking gradualism principles in ordinary circumstances, the stipulation in Docket No. 14-035-114 established a structure providing gradualism for customers with self-generation before the effectiveness of the rate to be determined here. In other words, no actual customer is likely to experience the immediate and dramatic reduction in compensation rates the eighty-three percent reduction would otherwise suggest.

The current docket was opened to explore an export credit rate and method that more accurately reflects the costs and benefits of customer generation. The Division understands that transitioning from a billing scheme that credits kWh for kWh to something that correlates to avoided system costs is bound to produce different results. However, the Division supports a rate that better reflects avoided system costs, which vary by the time of day.

Net metering billing schemes that credit kWh for kWh also create the problem of solar customers perhaps not paying a reasonable share of fixed system costs (virtual storage)--the cause of this entire six-year process. Ultimately, if not addressed, those costs would be shifted to other rate payers during a general rate case. RMP’s proposed rate design mitigates this cost shifting problem by delivering at a rate that includes fixed system costs while crediting at a rate that allows RMP to retain revenues to offset system costs.

The Division concludes RMP's proposal is a better method for export compensation because it is based on avoided cost theory[26] where export is paid at a rate that approximates a least-cost proxy generation resource that could take its place across a 24-hour day on any given day of the month throughout the year. Depending on where this proxy resource is located, the cost to operate it is a surrogate for BTM generation because other customers are not willing or expected to pay a higher cost for their energy needs when they can purchase it at a lower rate. The avoided cost methodology provides an opportunity for costs and benefits to be added to the basic avoided energy charge when prudent.

RMP's proposed rate structure offers rates[27] that compensate BTM generation customers a credit that offsets avoided costs that RMP has control over plus line losses that are avoided due to the distance between fleet generation and load. In-turn, the full schedule delivery rate is such that RMP has an opportunity to recover fixed system costs.

Q: Are customer generation and qualifying facility resources equivalent?

A: No. Solar Qualifying facilities ("QFs") are utility scale generation resources that supply power to the grid under either short-term or long-term contracts including capacity and reliability standards. QFs also provide guarantees with financial penalties for failure to meet delivery requirements. The utility can rely with a relatively high degree of

[26] See Commission Docket 03-035-14, In the Matter of the Application of PacifiCorp for Approval of an IRP Based Avoided Cost Methodology for QF Projects Larger Than 1 Mega Watt.

[27] Again, the Division is opining in this testimony about the structure of the rates proposed and will continue to evaluate the actual rate in light of market conditions in later rounds of testimony.

confidence in delivery of energy from solar QF multiple years into the future and may plan its generation around those resources being available. BTM customer generation varies in capacity across the state and does not have to meet any kind of standards other than those in the interconnection agreement.

Q: Is the Division concerned with the winter and summer seasons proposed by RMP?

A: At the time of this filing, the Division has not vetted RMP's proposed changes to include May in the winter months (October through May) versus current rate schedules that include May as a summer month. Generally, it would be preferable to have the compensation structures here match the seasonal rate changes in other tariffs.

RMP witness, Mr. MacNeil, explains in his direct testimony that the hourly price scalers for the month of May better align with the winter on-peak definition, as May prices are higher from 7:00 a.m. to 9:00 a.m. than between 4:00 p.m. and 6:00 p.m. as in the summer months.[28] The Division does not anticipate that this change bears a significant impact to the rate design but needs more time for analysis of its implications. This raises the question of whether the summer rate blocks in other schedules should also be set differently if the export credit has different value in May than in summer months.

Q: Is there any supporting evidence that RMP's proposed overall export credit rate of 1.5261 cents per kWh is just and reasonable?

[28] RMP witness, Daniel J. MacNeil, Direct Testimony, Docket No. 17-035-61, pg. 11 at lines 219-222.

A: Yes. The California Independent System Operator ("CAISO") publishes an interactive day-ahead and real-time marginal pricing map covering the West.[29] As noted earlier, the amounts of generation coming from customer-owned generation in the relevant schedules more closely resemble small, balancing-type purchases than planned purchases or generation. Accordingly, a real-time marginal price is more likely to reflect the value of the generation at issue in this docket. For example, the map illustrates a real time marginal energy price on February 10, 2020 at hour 12-13 for PacifiCorp East of $11.96 per MWh, or $0.01196 per kWh. The nodal value of delivered energy includes energy, congestion, and losses. Note that RMP uses an hourly load aggregation point ("LAP") shape based on a 15-minute PacifiCorp East ("PACE") EIM load aggregation point for the most recent thirty-six month period ending October 2019.[30] Illustration 17 shows the pricing for February 10, 2020.

[29] See California Independent System Operator ("CAISO"), http://www.caiso.com/PriceMap/Pages/default.aspx. Other sources that produce similar results are the NYISO, MISO, ISO New England, ERCOT, IESO, and AESO.
[30] RMP witness, Daniel J. MacNeil, Direct Testimony, Docket No. 17-035-61, pg. 4, lines 87-89.

Illustration 17

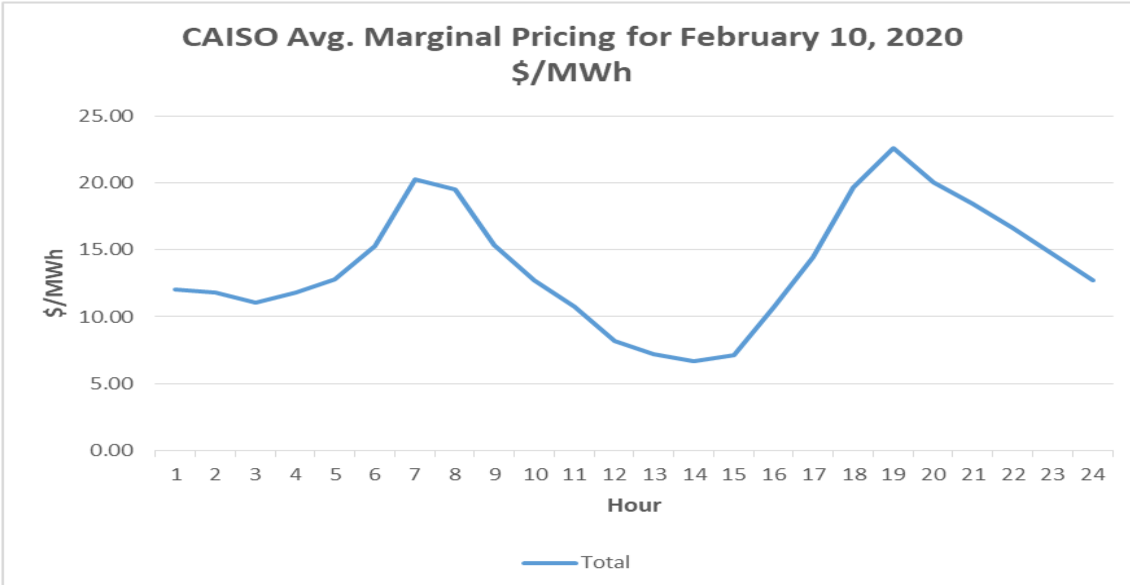
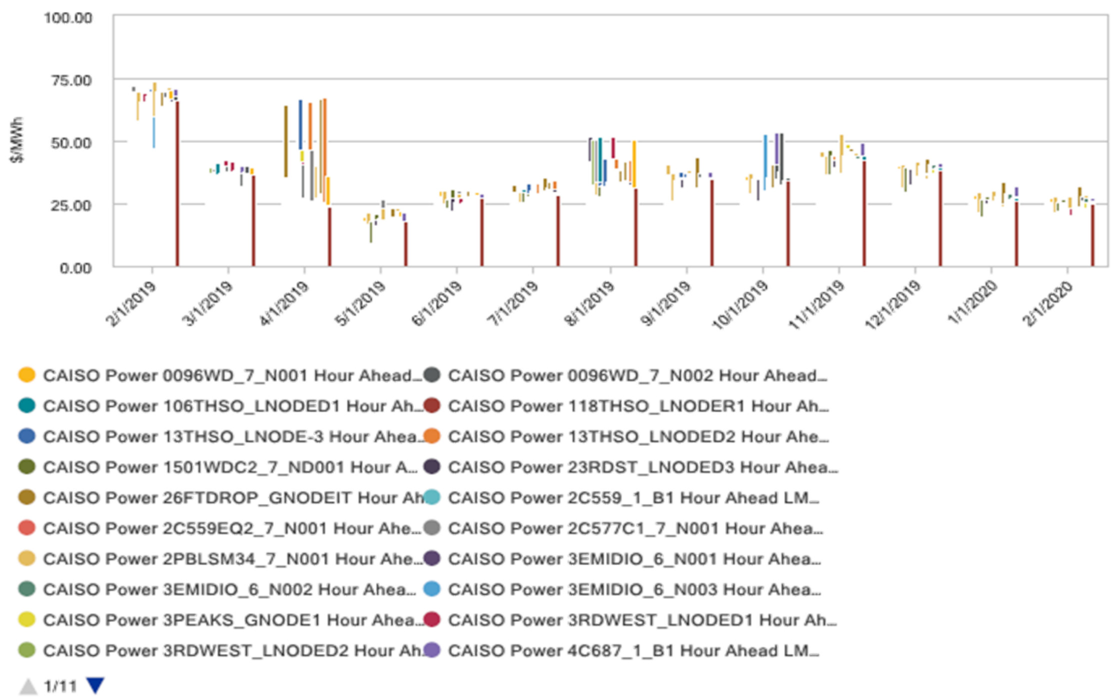


Illustration 18 is a historical snapshot of the location marginal pricing ("LMP") for all hours and nodes beginning February 1, 2019 from S&P Global Market Intelligence.[31]

[31] S&P Global Market Intelligence. (Membership required). 17-035-61_DPU Exhibit 1.2_Davis Dir_PH II_S&P Global Market Pricing_3-3-20.
https://platform.mi.spglobal.com/web/client?auth=inherit&overridecdc=1&ignoreidmcontext=1#markets/commoditiesChart?SerType=0&Source=7&ComType=1&Period=70&Fill=Monthly&AsOf=2020-02-01&selectedseries=0|s=7|l=15358|i=435|m=0,0|s=7|l=15379|i=435|m=0,0|s=7|l=15386|i=435|m=0

Illustration 18

S&P Global Historical Pricing for CAISO (West)



Illustrations 17 and 18 provide evidence that RMP's proposed rates are aligned with the market, which includes all generation types from fleet generation and qualifying facilities. The Division plans to review market pricing from multiple sources and include its conclusions in future rounds of testimony.

Q: Do you have other evidence that supports the reasonableness of RMP's proposed export credit rate?

A: Yes. RMP uses its Generation Regulation Initiative Decision Tool ("GRID") to model impacts from system configuration changes such as the IRP updates and avoided cost schedules to determine the rate QFs are offered for energy they export to the grid.

Schedule 37, Avoided Cost Purchases from Qualifying Facilities, is well vetted, has been in place for several years, and is peer reviewed on a quarterly basis. The assumptions that inform the GRID model consist of load shapes, the official forward price curve, current IRP results, and recent changes to executed contracts.[32] Division witness, Dr. Abdulle, discusses avoided cost methods and RMP's inputs in his direct testimony.

The Division concludes RMP's proposal utilizes a method that better reflects the actual costs and benefits to determine a reasonable rate for customer generated exports. It makes sense that energy exported to the grid from customer generation offsets energy, at least to some degree, produced by fleet resources, QFs, or front office transactions ("FOTs") with associated line losses and integrations costs. As customer generation penetration increases, ancillary services, such as frequency and VAR correction, might become valuable thus increasing the export credit.

Q: Does the Division find RMP's proposal to charge $150 for an application fee and $160 for a customer generation metering fee reasonable and in the public interest?

A: Yes. The Division is reviewing RMP's analysis for both fees at the time of this filing. Based on its findings thus far, the Division believes these charges are reasonable. For distributed generation customers, modern metering is essential. RMP's proposal will help in that endeavor. Advanced metering (AMI meters) have better functionality and aid in future cases by providing better data that describes how the system performs with distributed generation. In order to accurately set rates for these customers, the public

[32] RMP witness, Daniel J. MacNeil, Direct Testimony, Docket No. 17-035-61, pgs. 5-6, lines 96-125.

interest requires more sophisticated metering equipment, of the type covered by the proposed charge.

Q: Does the Division find RMP's proposal to make Schedule 137, if approved, effective January 1, 2021?

A: Yes. When a more accurate rate is ascertained, it should be used. The Division understands that customers who have contracts in place on December 31, 2020 will have twelve months to interconnect and six additional months for large non-residential customers if needed. Then, they will have years under the more advantageous rate structures in place currently. New customers have no right to expect a rate that is not cost-based to continue as they join the system.

VII. SUMMARY

Q: Will you summarize your analysis and findings for Phase Two of this docket and offer your recommendations?

A: Yes. The intent of customer generation is to give customers an opportunity to generate enough energy to offset their energy needs throughout the year. Customer generation is not comparable to a qualifying facility. The fact that solar generation is dependent upon sunlight makes it a non-dispatchable generation resource. During times of production, energy is consumed on site or exported to the grid as a credit. This credit offsets the customer's bill either as a kWh adjustment (Schedule 135) or kWh converted to a dollar amount (Schedule 136) throughout the year. The Division's analysis of the LRS data clearly shows that solar customers use the system differently than non-solar customers.

My testimony discusses the Division's analysis of the LRS and general support of RMP's proposed Schedule 137 customer generation compensation rates at this time. The LRS produced a voluminous amount of raw data that can be analyzed in any one of numerous ways depending on what the researcher is interested in learning. The Division's analysis centered on how much and when customer generation impacts the grid. During its analysis, the Division noticed a higher level of variability during certain months of the year. The variability raises questions about the impacts this may have on the system and a call for further research as BTM solar generation penetration levels increase.

RMP books the export credits as net power costs ("NPC") in its energy balancing account ("EBA").[33] EBA charges are added to all customer bills as a rider and not avoidable if the customer has BTM generation. It is prudent to ensure the export credit addition to NPC reflects actual costs.

The Division has not fully vetted RMP's proposed Schedule 137 at the time of this filing but generally finds RMP's proposal reasonable at this time. Evidence from other parties may alter conclusions to some degree. The proposal applies a method that better aligns export credits to avoided costs while giving RMP an opportunity to recover

[33] See Docket No. 14-035-114, Stipulation, August 28, 2017, pg. 11, ¶ 32. https://pscdocs.utah.gov/electric/14docs/14035114/296270RMPSettleStip8-28-2017.pdf.

fixed system costs. However, the Division needs time to analyze RMP's and other proposals in greater detail before recommending its approval to the Commission.

Q: Does this conclude your direct testimony?

A: Yes it does.

APPENDIX A

Compiled LRS Graphs for Residential and Non-Residential Samples

CONFIDENTIAL – Subject to Utah Public Service Commission Rules R746-1 602 and 603

SYSTEM and UTAH LOAD to SAMPLE EXPORTS

[redacted]

LRS NEW SAMPLE RESIDENTIAL

[redacted]

LRS NEW SAMPLE RESIDENTIAL EXPORT TOTALS

[redacted]

LRS NEW SAMPLE NON-RESIDENTIAL

[redacted]

REDACTED

LRS NEW SAMPLE NON-RESIDENTIAL EXPORT TOTALS

[redacted]

LRS ORIGINAL 36 NEM

[redacted]

LRS ORIGINAL 36 NEM EXPORT TOTALS

[redacted]

LRS STUDY SCH 136 RESIDENTIAL

[redacted]

LRS STUDY SCH 136 TOTAL EXPORTS

[redacted]

LRS STUDY SCH 136 NON-RESIDENTIAL

[redacted]

LRS STUDY SCH 136 NON-RESIDENTIAL TOTAL EXPORTS

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

TEMPERATURES for SALT LAKE CITY

[redacted]

PRECIPITATION for SALT LAKE CITY

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]