ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

February 3, 2020

VIA ELECTRONIC FILING

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

Attention: Gary Widerburg
Commission Administrator

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

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

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

By E-mail (preferred): datarequest@pacificorp.com
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Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Joelle R. Steward

February 2020

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Rocky Mountain Power ("Company").

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah 84116. My title is Vice President of Regulation for Rocky Mountain Power.

Qualifications

Q. Please describe your education and professional background.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. From February 2012 through May 2016, I was a Director in charge of the work for the cost of service, pricing, and regulatory operations groups for the Company. In 2016, I became the Director of Rates and Regulatory Affairs and added the regulatory affairs for Rocky Mountain Power to my responsibilities. In November 2017, I assumed my current position as Vice President of Regulation for Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Idaho, Oregon, Utah, Washington, and Wyoming.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- introduce and support the Company's proposed net billing program ("Net Billing Program") which includes an export credit rate that will be paid to customer generators for excess electricity ("Export Credit Rate"), consistent with the Settlement Stipulation in Docket No. 14-035-114 ("NEM Stipulation");
- provide a brief history on how net metering in Utah has evolved into the Company's proposed Net Billing Program;
- give a status update on the current cumulative nameplate capacity of the installations on Electric Service Schedule No. 136 – Transition Program for Customer Generators ("Schedule 136");
- provide an overview of the Company's proposed new tariff, Electric Service Schedule No. 137 ("Schedule 137") and an explanation of how it meets the parties' commitments in the NEM Stipulation; and
- introduce the witnesses who support the details of the Company's proposal.

Q. Please provide a summary of the Company's proposal in this proceeding.

A. The Company proposes a new Net Billing Program to provide credits to customer generators for all energy exported to the grid from their generation systems. Compensation to customers for exported energy will vary based on when the energy is exported, with different prices for summer, winter, on-peak, and off-peak times. Under the Company's proposal, all energy provided by the Company will be at customers' applicable electric service schedule rate. Energy generated and consumed on-site by customers will offset kilowatt-hours that would otherwise be provided by the Company. To implement this new program, the Company proposes Schedule 137, a successor program to Schedule 136. The Company also proposes other tariff changes to Schedule 136, to transition to Schedule 137, as well as an application fee.

Q. What does the Company want to accomplish with its proposal?

A. The Company's main objective is to implement a sustainable program structure for customer generators that fairly balances the interests of customer generators and other non-participating customers. The Company's proposal will better provide customers more accurate price signals to inform a decision on whether to invest in private generation facilities. The Company's proposal also minimizes impacts to other customers by not paying customer generators for exported energy in excess of its value. The Company's Net Billing Program offers a fair and balanced approach to support energy choices.

Q. Does the Company support renewable resources, including providing renewable resource service options to customers?

A. Yes. The Company supports the deployment of cost-effective renewable resources. This is demonstrated by the Company's own resource mix. From 2018 to 2020, the Company's Energy Vision 2020, which includes repowering existing wind resources and adding 1,150 megawatts ("MW") of new wind, will dramatically increase the percentage of zero-carbon energy resources in its portfolio by 70 percent. The Company's 2019 Integrated Resource Plan sets forth a plan to further expand its resource portfolio with approximately 6,000 MW of new low-cost wind generation, solar generation and storage through 2023[1]. In addition, the Company continues to meet its customers' growing preference for renewable resources through voluntary programs such as Blue Sky, Subscriber Solar, Electric Service Schedule 34 – Renewable Energy Purchases for Qualified Customers, and support for the new Community Renewable Program enacted by House Bill 411 in the 2019 legislative session. The Company is committed to meeting its customers' renewable needs while finding innovative ways to mitigate negative impacts to other customers.

Background

Q. How has net metering in Utah evolved?

A. The net metering program in Utah originated from an order issued by the Public Service Commission of Utah ("Commission") in Docket No. 97-035-01, which established a task force to analyze energy efficiency and renewable resources, including net metering.[2] The Energy Efficiency and Renewable Task Force recommended that a new metering program be established.[3] Pursuant to legislation, the net metering program began in 2002.[4] From its inception in 2002 until 2013, the net metering program experienced various changes to implement legislative amendments and a number of other program modifications.[5] During this timeframe, the price of solar panels rapidly decreased and government subsidies were implemented, resulting in rapid growth of

[1] PacifiCorp's 2019 Integrated Resource Plan, Chapter 1 – Executive Summary.
[2] *See In the Matter of the Investigation Into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company,* Report and Order (March 4, 1999), 1999 WL 35637961, at *68 (Utah P.S.C. March 4, 1999).
[3] Docket No. 97-2035-01, Report of the Energy Efficiency and Renewable Task Force, at 36 (Utah P.S.C. December 23, 1999).
[4] L. Utah 2002, Ch. 6.; See *also* Docket No. 02-035-T05, Tariff Approval Letter (Utah P.S.C. June 24, 2002).
[5] *See* Docket Nos. 08-035-78, 08-035-T04, 09-035-T03, 10-035-T04, 10-035-T12, 11-035-T05, 12-035-T09, 13-035-T09, 13-035-T10, and 14-035-T06.

net metering adoption. To address concerns of cost shifting due to an unsustainable ratemaking structure, the Company filed a general rate case in Docket No. 13-035-184 that included a proposal to implement a monthly facilities charge for residential customers on Electric Service Schedule No. 135 – Net Metering Service ("Schedule 135") to recover the fixed distribution and retail costs associated with serving net metering customers. In that proceeding, the Commission examined the issue and concluded that a separate docket was necessary to examine the costs and benefits of the Company's net metering program. The separate docket established by the Commission was Docket No. 14-035-114 ("NEM Docket").

Q. Please provide an overview of the NEM Docket.

A. On August 29, 2014, the Commission initiated the NEM Docket to evaluate the Company's net metering program in accordance with Utah Code Ann. § 54-15-105.1. This statutory provision requires the Commission to: (1) determine, after appropriate notice and opportunity for public comment, whether costs that the Company or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits. The NEM Docket was bifurcated to focus on each of these questions separately. Ultimately, on August 27, 2017, the majority of the parties[6] in the case agreed to the NEM Stipulation, which

[6] The following parties are signatories to the NEM Stipulation: PacifiCorp, Office of Consumer Services, Division of Public Utilities, Vivint Solar, Inc., Auric Solar, LLC, HEAL Utah, Intermountain Wind and Solar, LLC, Legend Ventures, LLC dba Legend Solar, LLC, Utah Solar Energy Association,, Salt Lake City Corporation, Utah Clean Energy, Summit County, Utah Citizens Advocating Renewable Energy, and Park City Municipal Corporation.

was approved by the Commission on September 29, 2017.

Q. What are the major aspects of the NEM Stipulation?

A. In summary, the NEM Stipulation:

1. Capped participation in the Schedule 135 net metering program at the cumulative generating capacity of all customer generating systems that submitted interconnection applications as of November 15, 2017 ("NEM Cap Date")[7];
2. Grandfathered Schedule 135 net metering customers in the net metering program through December 31, 2035 ("Grandfathering Period");
3. Established the transition program ("Transition Program") for customers who submitted an interconnection application after the NEM Cap Date but before a specified cap is met ("Transition Customers"). The cumulative interconnected nameplate capacity of all Transition Customers was capped at 170 MW for residential and small non-residential customers and 70 MW for large non-residential customers ("Transition Cap");
4. Fixed the compensation paid to Transition Customers on Schedule 136 for energy exported to the grid ("Export Credits") through December 31, 2032 ("Transition Period"), measuring and netting Transition Customers' usage and Export Credits using 15-minute intervals;
5. Provided the Company the ability to recover the energy payments it makes to the Transition Program customers through the Energy Balancing Account ("EBA");

[7] The NEM Stipulation set the NEM Cap Date to be the earlier of: (a) 60 days after the Commission issued an order approving the NEM Stipulation; or (b) November 15, 2017.

6. Set new customer generation interconnection fees and charges beginning on the NEM Cap Date;
7. Established a new proceeding to determine the compensation for exported power from customer generation systems ("Export Credit Proceeding"), including Transition Customers after expiration of the Transition Period and Schedule 135 Customers after expiration of the Grandfathering Period; and
8. Determined that customers who submit an interconnection application after the date the Transition Cap is reached but before a final order is issued in the Export Credit Proceeding will receive the Export Credit applicable to Transition Customers until the Commission issues a final order in the Export Credit Proceeding and a new tariff is implemented, after which such customers will be subject to the terms of the new tariff.

Q. Please elaborate about the purpose of the Export Credit Proceeding

A. The NEM Stipulation required an Export Credit Proceeding to determine the compensation rate for exported power from customer generation systems. In accordance with the NEM Stipulation, parties must take no longer than three years to complete the Export Credit Proceeding. Therefore, since the docket started on December 1, 2017, it must be resolved by the end of 2020. This docket was bifurcated into two phases: Phase one was adjudicated during 2018 to determine the load research study plan, which was implemented in 2019. Phase two begins with this filing and will determine the Export Credit Rate that will be paid to new customer generators after the Transition Program ends. In addition, the interconnection fees and charges identified in paragraph 17 of the NEM Stipulation are subject to reevaluation in this proceeding.

Q. When will the Export Credit Rate that is determined in this proceeding apply to customers on the Company's existing customer generation programs?

A. Per the terms of the NEM Stipulation, the Export Credit Rate established in this docket will apply to Schedule 135 customers on January 1, 2036 and to Schedule 136 customers on January 1, 2033.

Q. How will new customer generators be affected by this proceeding?

A. The NEM Stipulation states that customers who submit a complete interconnection application after the applicable Transition Cap is met, but before the Commission issues a final order in this proceeding, will receive the Transition Export Credit or the Modified Transition Export Credit (as applicable) until the Commission issues an order in the Export Credit Proceeding and a new tariff is implemented, at which time such customers will be subject to the terms of the new tariff, as determined by the Commission.[8]

Q. Please provide the current status of the Schedule 136 cumulative interconnections to date, compared to the Transition Cap.

A. The Transition Cap for residential and small non-residential customers is 170 MW. As of December 31, 2019, residential and small non-residential, defined by the NEM Stipulation to include rate schedules 1, 2, 3, 15, and 23, is currently at a cumulative interconnected nameplate capacity of 52.4 MW with approximately 36 MW pending. The Transition Cap for large non-residential customers is 70 MW. Currently, large non-residential rate schedules 6, 6A, 6B, 8 and 10 are at a cumulative interconnected nameplate capacity of 4 MW with approximately 11.8 MW pending.

[8] Transition Export Credit and Modified Transition Export Credit are described in paragraphs 19-21 of the NEM Stipulation.

Rocky Mountain Power Proposal

Q. Please summarize the Company's proposal.

A. The Company's proposal is a cost-based, reasonable approach that is consistent with the NEM Stipulation. In summary, the Company's proposal:

1) Recommends a net billing tariff for new customer generators. The net billing tariff will provide export credits to customer generators for all energy exported to the grid from their generation system. Customer energy use that is provided by the Company would be billed under the standard applicable tariff. Energy generated and consumed on-site by customers will serve to offset kilowatt-hours that would otherwise have been imported from the Company to the customer;
2) Presents a new schedule, Electric Service Schedule No. 137 – Net Billing Service, for new customer generators effective January 1, 2021;
3) Proposes an average Export Credit Rate of 1.526 cents per kilowatt-hour. The Export Credit will be applied differentially, based on the time of day and season when the energy is exported. Under the Company's proposal, the prices would be updated annually;
4) Implements a one-time, non-refundable application fee of $150 for interconnection applications under Schedule 137;
5) Implements a one-time, customer generation meter fee of $160 for interconnection applications under Schedule 137;

6) Closes Schedule 136 to new applications received after December 31, 2020. Customers who submit a complete interconnection application prior to December 31, 2020 will have a 12 month period to interconnect.

Q. How does Schedule 137 achieve a fair and balanced outcome for all customers?

A. A customer with on-site generation should be paid for any exported energy at a rate that is competitive with what customers pay for other energy with similar characteristics, rather than at the full retail rate. The Company does not propose paying customers less than market value for their exported energy. At the same time, the Company does not believe that non-participating customers should subsidize customers with on-site generation. A fair and balanced solution is achievable while maintaining Utah's energy rates, which are among the lowest in the nation. The Company's request presents a simple, fair, and balanced solution: (1) customers should pay the cost for the energy they use; and (2) customers with on-site generation should receive fair value for energy they export that is comparable to what could be procured from alternative sources of energy.

Q. What is the proposed structure for the new Net Billing Program?

A. The Company proposes to implement a Net Billing Program that would provide credits to customer generators for all energy exported to the grid from their generation systems. The compensation for exported energy will vary based on the time at which the energy is exported, with different prices for summer, winter, on-peak, and off-peak times. All energy usage provided by the Company will be at customers' applicable electric service schedule rate, which is applicable to all similarly situated customers. Energy generated and consumed on-site by customers will offset kilowatt-hours that would otherwise have been provided by the Company.

Q. Did the NEM Stipulation address recovery of the Export Credits for Schedule 136?

A. Yes. Paragraph 32 of the NEM Stipulation states:

> The difference between: a) export credits to Transition Customers throughout the Transition Period and export credits to Post-Transition Customers until the tariff is implemented after the Export Credit Proceeding and b) the market value of these exports adjusted for line losses will be recovered 100 percent through the Energy Balancing Account or another pass-through mechanism as determined by the Commission on a Utah-situs basis. In the Export Credit Proceeding, or appropriate subsequent proceeding, the Parties may address the methodology for calculating the amount for recovery of the export credits to be run through the Energy Balancing Account or other pass-through mechanism, and the treatment of export credit recovery, including situs assignment, to be implemented after the Export Credit Proceeding for Post-Transition Customers and customers interconnecting after the Export Credit Proceeding, provided, however, that the recovery of the Commission-approved amount remains 100 percent.

Per the NEM Stipulation, the Company has been recovering the export credits paid to Schedule 136 customers through the EBA.

Q. Does the Company propose to continue this treatment?

A. Yes. The Company also proposes to recover the Export Credits paid to Schedule 137 customers through the EBA in the same manner.

Q. Please identify the other witnesses supporting the Company's filing and the subject of their testimony.

A. Mr. Robert M. Meredith, will present the Company's proposed Schedule 137, Net Billing Program, and tariff changes to Schedule 136 that will effectuate an orderly transition to the new program. Mr. Daniel J. MacNeil will describe the valuation of excess exported customer generation.

Conclusion

Q. What is your recommendation for the Commission?

A. The Company requests that the Commission approve the proposals set forth in this application. The Company's proposals would implement a new Net Billing Program that allows customers to choose to invest in onsite customer generation systems while protecting customers who do not invest in these systems from the cost-shifting impacts of those choices.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Robert M. Meredith

February 2020

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("the Company").

A. My name is Robert M. Meredith. My business address is 825 N.E. Multnomah St, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Cost of Service.

Qualifications

Q. Briefly describe your educational and professional background.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 15 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over nine years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the company in regulatory proceedings in Utah, Wyoming, Idaho, Oregon, Washington, and California.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents the Company's proposed Schedule 137, Net Billing Service, a successor program to Schedule 136, Transition Program for Customer Generators, for customer generators along with tariff changes to Schedule 136 which would effectuate an orderly transition to the new program. My testimony includes a description of the proposed export credit rates, a discussion of how the proposed Net Billing program would work, and a presentation of an analysis that supports the Company's proposed application fee.

Proposed Net Billing Tariff

Q. Please present the Company's proposed Net Billing tariff.

A. The Company's proposed Net Billing program is set forth in the proposed tariff Schedule 137, Net Billing Service which is provided in Exhibit RMP___(RMM-1). The program will provide export credits to customer generators for all energy exported to the grid from their generation system. At the same time, all energy usage provided by the Company to the customer would be billed under the standard applicable tariff. Energy generated and consumed on-site will serve to offset kilowatt-hours that would otherwise have been imported from the Company to the customer. The price provided for export credits will be updated annually on July 1.

Q. How is the Company's proposed Net Billing program different than Schedule 136 – Transition Program for Customer Generators, the customer generation program currently available?

A. There are several key differences that the Company proposes for the Net Billing program. Instead of receiving a fixed locked-in price for export credits that is based upon 90 percent of average energy charges, the export credit price for the Net Billing program would be based upon the actual value for exported energy as it varies across seasons (summer and winter) and time of use periods (on- and off-peak). Export credit prices under the Net Billing program would be updated annually to reflect the most up-to-date information. This will ensure that costs are not shifted onto other customers and the prices paid for exported energy evolve with their value over time. The Company also proposes that there be no interval netting of exported and delivered energy in the Net Billing program. Export credits would be provided to customer generators for all energy exported to the grid and standard retail tariff charges would apply to all energy delivered to the customer. This is different from Schedule 136, where exported and delivered energy are netted on a 15 minute interval basis. Finally, the Company proposes a flat non-refundable $150 application fee for customers seeking to participate in the Net Billing program along with a $160 customer generation metering fee.

Q. What is the proposed export credit rate for exported energy?

A. The overall proposed export credit rate is 1.5261 cents per kilowatt-hour. The basis for this rate is described in the testimony of Company witness Mr. Daniel J. MacNeil. The Company proposes that this export credit rate be applied to energy based upon the time at which it is exported. During the summer months of June through September, energy exported during the on-peak hours of 4pm to 8pm, Monday through Friday excluding holidays would receive a 2.6293 cents per kilowatt-hour credit. During all other hours, which would be considered off-peak, energy exported would receive a 1.7080 cents per kilowatt-hour credit. During the winter months of October through May, a 2.2409 cents per kilowatt-hour credit would apply to on-peak exported energy between 7am to 9am and 6pm to 8pm, Monday through Friday excluding holidays. A 1.3247 cents per kilowatt-hour credit would apply to off-peak exported energy during all other hours.

Q. Will the Company credit or charge customers for kilowatt-hours that are generated by the customer and consumed on-site?

A. No. Kilowatt-hours generated and consumed on-site will lower the customer generator's imported energy needs from the Company, thereby lowering their electric bill from the standard tariff. There will be no other charge or credit for these kilowatt-hours under the proposed Net Billing program.

Q. Why does the Company propose that exported energy credit prices be differentiated by season and time of export?

A. Differentiating the price of exported energy better reflects the costs and benefits of distributed energy resources and encourages customers to build and operate their systems in ways that are the most beneficial to the power grid. For example, customer generation is most valuable to the power grid in the early evening period in the summer. Differentiated pricing encourages customers to shift their export of energy from the low usage, middle of the day, to the higher value, early evening period. This shift encourages energy production during costly periods when the demand for energy increases rapidly from diminishing solar production and increasing net residential usage. The higher compensation for exported energy during the on-peak periods will encourage customers to find innovative solutions to their energy needs such as building west facing systems which generate more energy later in the day. Along with building generation systems that produce more during on-peak periods, customer generators can achieve more value from their system by shifting consumption to use more of their energy production during high output off-peak periods. For example, customer generators could set a timer for their dishwasher to run or their electric vehicle to charge during sunny, middle of the day off-peak times. Innovations, along with conscious energy choices in the home, will contribute to a more efficient power grid and lower net power costs for all customers. By offering a higher credit price during the on-peak period, the Company is fairly compensating the customers that export energy during periods when energy is more valuable and encouraging customers to invest in innovation.

Q. How often would export credit prices be updated on proposed Schedule 137?

A. The Company proposes to update export credit rates annually. By April 30 each year, the Company would make a filing with updated prices to be effective July 1.

Q. Under what interval will energy exported to the grid and energy delivered from the Company be netted against each other?

A. The energy exported to the grid and energy delivered from the Company would not be netted against each other over an interval period. Customers' billings would be based upon total energy exported and total energy delivered for each monthly billing cycle. These energy measurements would be computed in real time and would not rely upon a specific interval period such as a 15 minute or hourly interval.

Q. Why is the Company proposing no netting of energy for this program like Schedule 136 where exported and delivered energy are netted on a 15 minute interval basis?

A. There are three reasons why the Company is proposing no interval netting for the proposed program. First, using an interval over which exports and imports are netted masks the intertemporal reality of the service that the Company provides. One benefit of the Company's proposed Net Billing program is that it sends a price signal for customer generators to align their usage with their generation output. This can benefit the Company and other non-participating customers by accurately accounting for the load that the customers with generation draw from the system. Netting over an interval period, such as 15 minutes or an hour, sends a weaker price signal for customer generators to match usage with generation. With the scale of customer generation that has been adopted in the Company' service territory[1], encouraging alignment of loads with intermittent generation has never been more important. When a cloud rolls by an area where extensive customer generation is present, the energy on the system will suddenly drop and the Company must provide the power demanded. Indeed, every fraction of a second the Company must serve the load requirements of its customers as they fluctuate in real time. Sending a robust price signal to match customer generation with load as the Company has proposed in its Net Billing program provides a greater opportunity for customer generators to benefit the system.

Second, using total exported energy and total delivered energy in the billing calculation is a simpler concept to explain to customers than netting over each 15 minute interval. It is much easier for someone to understand that all energy sent to the grid will get a certain export price and all energy delivered to the customer will be billed at standard tariff rates than to describe how energy is netted in every 15 minute period.

Finally, using the registers for exported and delivered energy instead of relying upon profile data to bill customers is less administratively burdensome for the Company. Without netting, the Company's meters will simply record energy delivered and energy exported in the on- and off-peak time periods and send those registers to the Company's billing system to calculate a bill for the customer. While the Company

[1] As of the end of December 2019, 38,546 customers has interconnected about 309 megawatts of customer generation in the Company's Utah service territory.

has automated much of the process for billing Schedule 136 customers based upon 15 minute intervals, there still is some backend manual work that is required to accurately bill customers. Fifteen minute interval netting requires profile data for each meter which on average includes 2,920[2] reads for each monthly billing period. Most of the time, there are no issues with this data, but when there are, Company employees must resolve them. The Company's proposed program which has no interval netting would avoid this added workload.

Q. What difference can 15 minute interval netting make to the volume of exported energy?

A. Examining the metering data from Schedule 136 from the 12 month period ending December 31, 2019 shows that netting energy on a 15 minute interval basis makes very little difference in the total volume of exported energy to be used for billing. Exhibit RMP___(RMM-2) shows the results of this comparison. With 15 minute interval netting, the Company estimates that exported energy was about 50.5 percent of overall customer generation. Without netting, the Company estimates that exported energy would be 52.3 percent of overall customer generation.

Q. Under the Company's proposed Net Billing program, will export credits ever expire?

A. Yes. The Company's proposed Net Billing program is for customers to offset some or all of their energy bill with onsite generation, not for a customer to become a power producer. To encourage customers to appropriately size their generation systems to match actual usage at the site of the system, the Company proposes that export credits

[2] (365 days in a year * 24 hours in a day * 4 intervals in an hour) / 12 monthly billing periods in a year.

may be rolled over until March of each year for most customers and until October for irrigation customers. This proposal allows customers a reasonable opportunity to accumulate and use credits to offset actual energy use at the location of the distributed energy system.

Q. Will export credits be able to offset a customer's entire monthly bill?

A. No. The Company proposes that export credits be able to offset all charges on the customer generator's monthly bills except for customer service charges. All customers, including those with onsite generation, should be responsible for paying customer service charges which are designed to reflect some of the fixed aspects of service like having a meter and getting a bill that are not avoided regardless of how much a customer generates.

Q. Please describe how the proposed Schedule 137 Net Billing program tariff is similar to the Schedule 136 Transition program tariff.

A. Schedule 137 contains the same provisions related to safely interconnecting to customers' systems. It also grants the Company the ability to install production meters for research purposes and provides participants the opportunity to aggregate meters under the same provisions in Schedule 136.

Proposed Schedule 136 Tariff Changes

Q. What changes does the Company propose for existing Schedule 136?

A. To comply with the terms of the Settlement Agreement filed on August 28, 2017 in Docket No. 14-035-114 ("NEM Settlement") and to efficiently transition to the new Net Billing successor program, the Company proposes to revise Schedule 136 to close it to new applications for service and to provide customers with a 12 month period to interconnect with a 6 month extension available upon request for Large Non-Residential Customers. Exhibit RMP___(RMM-1) shows proposed tariff revisions for Schedule 136 with the added heading of "Closed to Applications for New Service as of January 1, 2021". Paragraph 15 of the NEM Settlement specifies that the applications may be submitted for the transition program for customer generators up to the earlier of the date the transition cap is reached or the date the Commission issues a final order in the Export Credit Proceeding. Proposed tariff sheets for Schedule 136 list January 1, 2021 as an illustrative placeholder date for the date when the program would be closed to new applications. After either the cap is reached or the Commission issues its final order, the Company would make a compliance filing reflecting the actual date that either of these events occurred.

The Company also proposes to add a Special Condition to clarify that "A Customer submitting an application for service under this Schedule has 12 months from the Customer's receipt of confirmation that the interconnection request is approved to interconnect. Large Non-Residential Customers will be allowed a six-month extension of the 12-month interconnection deadline upon request." This provision which is identical to what is in the Net Metering tariff (Schedule 135) will give customers a reasonable amount of time to interconnect their customer generation system after they submit their application and still qualify for Schedule 136.

Proposed Application Fee

Q. Please explain the Company's proposed application fee for customers seeking service on Schedule 137.

A. The Company proposes a onetime non-refundable $150 application fee which reflects the administrative cost associated with processing and approving applications for interconnection.

Q. How was this application fee calculated?

A. Exhibit RMP___(RMM-3) shows the calculation. The Company reviewed actual costs incurred to process applications for customer generation interconnections in the twelve month period ending June 30, 2019. These costs include administrative review and processing, engineering reviews, and customer service expense. The Company's overall cost to process Schedule 136 customer generator applications in the state of Utah was $732,893. Dividing this overall cost by 4,727 applications for Schedule 136 that were received in Utah yields a cost of roughly $155 per application. The Company proposes rounding this amount down to $150.

Q. Why is an application fee the appropriate mechanism for recovering these costs?

A. The cost of processing customer generator interconnection applications is driven by the volume of those applications; thus, it is appropriate and sensible for these costs to be recovered from the customers on whose behalf the costs were incurred. A further benefit is that an application fee can limit the number of unnecessary applications, thereby lowering the costs associated with their processing and approval. For example, without a charge, a customer or installer may submit an application even if the customer is not very serious about installing a customer generation system, because he or she faces no cost to apply. The Company would still incur costs related to that application even if no customer generation system is ever installed. Charging a small application fee may prevent some of the customers who are not serious about installing a new customer generation system, from applying.

Q. Why is the Company not proposing separate application fees for Levels 1, 2, and 3 like it does in Schedule 136?

A. The Company is only proposing a single fee of $150 for each Schedule 137 application to simplify its application process and make the cost of interconnecting more transparent for customers.

Q. Does the Company also propose a fee for the added cost of a new meter like the Schedule 136 meter fee?

A. Yes. The Company proposes a $160 customer generation metering fee for new Schedule 137 participants. After a customer interconnects customer generation, the Company must measure the quantities of energy that are both delivered to the customer and exported by the customer to the grid in order to bill the customer. 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. Exhibit RMP___(RMM-4) shows that taking 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 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.

Q. Please summarize your testimony.

A. The Company's proposed Net Billing program will provide customers with an opportunity to interconnect renewable energy systems to the Company's system and be fairly compensated for the energy they provide to the grid while holding other customers harmless. The Net Billing program is fair, just, in the public interest, and provides reasonable, cost-based compensation to customer generators for their output.

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission approve its proposed tariff Schedule 137, Net Billing Service.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

February 2020

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 136

STATE OF UTAH

Transition Program for Customer Generators
Closed to Applications for New Service as of January 1, 2021

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: On a first-come, first-served basis to a customer that owns or leases a customer-operated renewable generating facility or, an eligible customer that purchases electricity from an independent energy producer operating a renewable generating facility, with a capacity of not more than twenty-five (25) kilowatts for a residential facility or two (2) megawatts for a non-residential facility that is located on, or adjacent to, the customers' premises, is interconnected and operates in parallel with the Company's existing distribution facilities, is intended primarily to offset part or all of the customer's own electrical requirements, is controlled by an inverter capable of enabling safe and efficient synchronous coupling with Rocky Mountain Power's electrical system, and has executed an Interconnection Agreement for Transition Program Service with the Company. This Schedule shall be available up to a cumulative cap of 170 megawatts (direct current) of Installed Capacity for residential and small non-residential customers, and up to a cumulative cap of 70 megawatts (direct current) of Installed Capacity for large non-residential customers. This Schedule is offered in compliance with the Commission order dated September 29, 2017 in Docket No. 14-035-114.

TERM: Service under this Schedule will terminate on December 31, 2032.

DEFINITIONS:

An Inverter means a device that converts direct current power into alternating current power that is compatible with power generated by the Company.

Annualized Billing Period for all customers except Customers taking service under Electric Service Schedule 10 means the period commencing after the regularly scheduled meter reading for the month of March or in the case of new Schedule 136 service customers, the date that the customer first takes service on Schedule 136 and ending on the regularly scheduled meter reading for the month of March. The Annualized Billing Period for Schedule 10 Customers shall commence after the regularly scheduled meter reading for the month of October, or for new Schedule 10 Customers beginning service on Schedule 136, the date that the customer first takes service on Schedule 136 and

(continued)

ending on the regularly scheduled meter reading for the month of October.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 136 – Continued

17. A Customer submitting an application for service under this Schedule has 12 months from the Customer's receipt of confirmation that the interconnection request is approved to interconnect. Large Non-Residential Customers will be allowed a six-month extension of the 12-month interconnection deadline upon request.

~~17.~~18. Upon the customer-generator's request and within thirty (30) days' notice to the Company, the Company shall aggregate for billing purposes the meter to which the net metering facility is physically attached ("designated meter") with one or more meters ("additional meter") if the following conditions are met:
(a) the additional meter is located on or adjacent to premises of the customer-generator;
(b) the additional meter is used to measure only electricity used for the customer-generator's requirements;
(c) the designated meter and additional meter are subject to the same rate schedule; and
(d) the designated meter and the additional meter are served by the same primary feeder.

At the time of notice to the Company, the customer-generator must identify the designated meter at which Exported Customer-Generator Energy will be measured and netted, and the specific aggregated meters and a rank order for the aggregated meters to which the computed export credit is to be applied. The Customer may change the designated meter and ranking once in a 12-month period. If a change in the designated meter requires installation of a new meter capable of measuring 15-minute intervals, a new meter fee may apply. Aggregation services for billing purposes will be subject to the following fees:
(e) two to five aggregated meters - $2.00 per meter per month
(f) six or more aggregated meters - $25.00 per month flat fee

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 136

STATE OF UTAH

Transition Program for Customer Generators
Closed to Applications for New Service as of January 1, 2021

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: On a first-come, first-served basis to a customer that owns or leases a customer-operated renewable generating facility or, an eligible customer that purchases electricity from an independent energy producer operating a renewable generating facility, with a capacity of not more than twenty-five (25) kilowatts for a residential facility or two (2) megawatts for a non-residential facility that is located on, or adjacent to, the customers' premises, is interconnected and operates in parallel with the Company's existing distribution facilities, is intended primarily to offset part or all of the customer's own electrical requirements, is controlled by an inverter capable of enabling safe and efficient synchronous coupling with Rocky Mountain Power's electrical system, and has executed an Interconnection Agreement for Transition Program Service with the Company. This Schedule shall be available up to a cumulative cap of 170 megawatts (direct current) of Installed Capacity for residential and small non-residential customers, and up to a cumulative cap of 70 megawatts (direct current) of Installed Capacity for large non-residential customers. This Schedule is offered in compliance with the Commission order dated September 29, 2017 in Docket No. 14-035-114.

TERM: Service under this Schedule will terminate on December 31, 2032.

DEFINITIONS:

An Inverter means a device that converts direct current power into alternating current power that is compatible with power generated by the Company.

Annualized Billing Period for all customers except Customers taking service under Electric Service Schedule 10 means the period commencing after the regularly scheduled meter reading for the month of March or in the case of new Schedule 136 service customers, the date that the customer first takes service on Schedule 136 and ending on the regularly scheduled meter reading for the month of March. The Annualized Billing Period for Schedule 10 Customers shall commence after the regularly scheduled meter reading for the month of October, or for new Schedule 10 Customers beginning service on Schedule 136, the date that the customer first takes service on Schedule 136 and ending on the regularly scheduled meter reading for the month of October.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 136 – Continued

17. A Customer submitting an application for service under this Schedule has 12 months from the Customer's receipt of confirmation that the interconnection request is approved to interconnect. Large Non-Residential Customers will be allowed a six-month extension of the 12-month interconnection deadline upon request.

18. Upon the customer-generator's request and within thirty (30) days' notice to the Company, the Company shall aggregate for billing purposes the meter to which the net metering facility is physically attached ("designated meter") with one or more meters ("additional meter") if the following conditions are met:
    (a) the additional meter is located on or adjacent to premises of the customer-generator;
    (b) the additional meter is used to measure only electricity used for the customer-generator's requirements;
    (c) the designated meter and additional meter are subject to the same rate schedule; and
    (d) the designated meter and the additional meter are served by the same primary feeder.

    At the time of notice to the Company, the customer-generator must identify the designated meter at which Exported Customer-Generator Energy will be measured and netted, and the specific aggregated meters and a rank order for the aggregated meters to which the computed export credit is to be applied. The Customer may change the designated meter and ranking once in a 12-month period. If a change in the designated meter requires installation of a new meter capable of measuring 15-minute intervals, a new meter fee may apply. Aggregation services for billing purposes will be subject to the following fees:
    (e) two to five aggregated meters - $2.00 per meter per month
    (f) six or more aggregated meters - $25.00 per month flat fee

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 137

STATE OF UTAH

Net Billing Service

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: To a customer that owns or leases a customer-operated renewable generating facility or, an eligible customer that purchases electricity from an independent energy producer operating a renewable generating facility, with a capacity of not more than twenty-five (25) kilowatts for a residential facility or two (2) megawatts for a non-residential facility that is located on, or adjacent to, the customers' premises, is interconnected and operates in parallel with the Company's existing distribution facilities, is intended primarily to offset part or all of the customer's own electrical requirements, is controlled by an inverter capable of enabling safe and efficient synchronous coupling with Rocky Mountain Power's electrical system, and has executed an Interconnection Agreement for Transition Program Service with the Company.

DEFINITIONS:

An Inverter means a device that converts direct current power into alternating current power that is compatible with power generated by the Company.

Annualized Billing Period for all customers except Customers taking service under Electric Service Schedule 10 means the period commencing after the regularly scheduled meter reading for the month of March or in the case of new Schedule 137 service customers, the date that the customer first takes service on Schedule 137 and ending on the regularly scheduled meter reading for the month of March. The Annualized Billing Period for Schedule 10 Customers shall commence after the regularly scheduled meter reading for the month of October, or for new Schedule 10 Customers beginning service on Schedule 137, the date that the customer first takes service on Schedule 137 and ending on the regularly scheduled meter reading for the month of October.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 137 – Continued

DEFINITIONS: (continued)

Installed Capacity is the nameplate capacity measured in watt direct current (DC).

Residential Customer means any customer that receives electric service under Electric Service Schedules 1, 2, 2E or 3.

Non-Residential Customer means any customer that does not receives electric service under Electric Service Schedules 1, 2, 2E or 3.

Renewable Generating Facility means a facility that uses energy derived from one of the following:

a) solar photovoltaics;
b) solar thermal energy;
c) wind energy;
d) hydrogen;
e) organic waste;
f) hydroelectric energy;
g) waste gas and waste heat capture or recovery;
h) biomass and biomass byproducts, except for the combustion of wood that has been treated with chemical preservatives such as creosote, pentachlorophenol, chromated copper arsenate, or municipal waste in a solid form;
i) forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce wildfire risk;
j) agricultural residues;
k) dedicated energy crops;
l) landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters, or municipal solid waste; or
m) geothermal energy.

Exported Customer-Generated Energy means the amount of customer-generated Energy in excess of the customer's on-site consumption that is exported to the grid.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 137 – Continued

MONTHLY BILL: Energy charges for electricity consumption shall be computed in accordance with a Customer's applicable standard service tariff. Credits for Exported Customer-Generated Energy, if any, shall be computed at the following rates. Regardless of whether the Customer exports net generation during the month, the Customer shall be billed the minimum monthly amount from the applicable standard service tariff. All other charges shall be calculated in accordance with the Customer's applicable standard service tariff.

Exported Customer-Generated Energy Credit Rates:

Billing Months – June through September inclusive
2.6293¢ per kWh for all On-Peak kWh
1.7080¢ per kWh for all Off-Peak kWh

Billing Months – October through May inclusive
2.2409¢ per kWh for all On-Peak kWh
1.3247¢ per kWh for all Off-Peak kWh

TIME PERIODS:

On-Peak: October through May inclusive
7:00 a.m. to 9:00 a.m. and 6:00 p.m. to 8 p.m., Monday thru Friday, except holidays.
June through September inclusive
4:00 p.m. to 8:00 p.m., Monday thru Friday, except holidays.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 137 – Continued

SPECIAL CONDITIONS:

1. Applications for service under this schedule will be subject to the following fees, in addition to any other applicable charges in Public Service Commission Rule R746-312-13:
   a) Interconnection review request (non-refundable) - $150.
   b) Customer Generation Metering Fee - $160.
   The Customer Generation Metering Fee will be refundable to the Customer if the application process is terminated prior to metering changes.

2. Energy Charges in the applicable standard service tariff shall be computed from the total purchased Energy for the billing period.

3. The credit value in dollars computed for the Exported Customer-Generated Energy will be applied against the Power and Energy Charges on the Customer's monthly bill. Excess credits will carry-over to the next monthly bill during the Annualized Billing Period.

4. All unused credits accumulated by the customer-generator shall expire with the regularly scheduled meter reading at the conclusion of the Annualized Billing Period.

5. The customer-generator shall provide at the customer's expense all equipment necessary to meet applicable local and national standards regarding electrical and fire safety, power quality, and interconnection requirements established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories.

6. For customer-generator generation systems of 10 kilowatts or less that are inverter-based, a disconnect switch is not required. For all other generation systems, the customer-generator must install and maintain a manual disconnect switch that will disconnect the generating facility from the Company's distribution system. The disconnect switch must be a lockable, load-break switch that plainly indicates whether it is in the open or closed position. Except as provided in R746-312-4(2) (a) (ii), the disconnect switch must be readily accessible to the Company at all times and located within ten (10) feet of the Company's meter.

7. The Customer shall be responsible for the design, installation, operation and maintenance of the customer generation system and ensure that the customer generation system is in compliance with applicable codes. The Company shall not be held directly or indirectly liable for permitting or continuing to permit an interconnection of a customer-generation facility, or for an act or omission of a customer-generator in this program for loss, injury, or death to any third party. A Customer participating under this Schedule shall hold harmless and indemnify Rocky Mountain Power for all loss to third parties resulting from the operation of the Customer Generation Facility.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 137 – Continued

SPECIAL CONDITIONS: (continued)

8. The Company may test and inspect an interconnection at times that the electrical corporation considers necessary to ensure the safety of electrical workers and to preserve the integrity of the electric power grid.

9. Unless otherwise agreed to by a separate contract, the owner of the renewable energy facility retains ownership of the non-energy attributes associated with electricity the facility generates.

10. A Customer participating under this Schedule may be randomly selected for installation of one or more profile meters, which may include a meter to measure production from a customer generation system. If randomly selected, a Customer must allow the Company to install load research meters at a mutually convenient location. Installation of profile meters will not impact customer bills.

11. Service to a Customer under this Schedule may be terminated if: (a) the equipment approved for interconnection is affirmatively removed from service for any reason other than on a short-term basis for replacement of equipment, or repair of equipment or underlying structure, (b) the Customer makes a material modification to increase the size of the customer's generation system after interconnection, or (c) the Customer chooses to voluntarily change to another available customer generation program. If any of these conditions apply, the Customer must submit a new application for interconnection of the customer generation system under the applicable rules and tariff in effect at the time.

12. Upon the customer-generator's request and within thirty (30) days' notice to the Company, the Company shall aggregate for billing purposes the meter to which the net metering facility is physically attached ("designated meter") with one or more meters ("additional meter") if the following conditions are met:
    (a) the additional meter is located on or adjacent to premises of the customer-generator;
    (b) the additional meter is used to measure only electricity used for the customer-generator's requirements;
    (c) the designated meter and additional meter are subject to the same rate schedule; and
    (d) the designated meter and the additional meter are served by the same primary feeder.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 137 – Continued

SPECIAL CONDITIONS: (continued)

At the time of notice to the Company, the customer-generator must identify the designated meter at which Exported Customer-Generator Energy will be measured and netted, and the specific aggregated meters and a rank order for the aggregated meters to which the computed export credit is to be applied. The Customer may change the designated meter and ranking once in a 12-month period. If a change in the designated meter requires installation of a new meter capable of measuring 15-minute intervals, a new meter fee may apply. Aggregation services for billing purposes will be subject to the following fees:

(e) two to five aggregated meters - $2.00 per meter per month
(f) six or more aggregated meters - $25.00 per month flat fee

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

(continued)

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Comparison of Energy for Total Exports and 15 Minute Netted Exports

February 2020

Rocky Mountain Power
State of Utah
Schedule 136
Comparison of Energy for Total Exports and 15 Minute Netted Exports
12 Months Ended December 31, 2019

	Exported Energy (kWh)			Export % of Cust. Gen.	
SCHEDULE	15 Min Netting	Total (No Netting)	Est. Customer Generation (kWh)	15 Min Netting	Total (No Netting)
1-136	24,251,575	25,146,774	46,278,059	52.4%	54.3%
2-136	14,284	15,106	22,760	62.8%	66.4%
3-136	132,674	138,748	281,908	47.1%	49.2%
6-136	380,300	398,315	2,335,279	16.3%	17.1%
6A-136	13,802	15,480	143,844	9.6%	10.8%
8-136	0	0	66,720	0.0%	0.0%
23-136	466,756	475,709	923,341	50.6%	51.5%
TOTAL	**25,259,391**	**26,190,132**	**50,051,912**	**50.5%**	**52.3%**

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Customer Generator Application Fee Calculation

February 2020

PACIFICORP
State of Utah
Proposed Customer Generator Application Fee Calculation

	Total Cost for Utah	Customer Generator Applications in Utah	Cost per Application
Administration	$574,489	4,727	$122
Engineering Review	$108,851	4,727	$23
Customer Service	$49,553	4,727	$10
Total	$732,893	4,727	$155

Rocky Mountain Power
Exhibit RMP___(RMM-4)
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 137 Customer Generation Meter Fee

February 2020

Rocky Mountain Power
State of Utah
Proposed Schedule 137 Customer Generation Meter Fee

Line No.			
1	Cost to Replace a Non-AMI Meter	$95.00	
2	Overhead at 10.8%	$10.26	
3	Labor to Exchange Meter	$88.00	
4	Total Cost to Replace a Non-AMI Meter	$193.26	[1 + 2 + 3]
5	Labor to Re-Program an AMI Meter	$20.00	
6	Estimated Utah AMI Meters (End of 2021)	190,000	
7	Estimated Total Utah Meters (End of 2021)	1,000,000	
8	AMI Proportion of Meters (End of 2021)	19%	[6 / 7]
9	Non-AMI Proportion of Meters (End of 2021)	81%	[(7 - 6) / 7]
10	Weighted Cost of Metering for New Customer Generators	$160.34	[4 * 9 + 5 * 8]
11	Proposed Customer Generation Meter Fee	**$160**	

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

February 2020

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

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Resource and Commercial Strategy Adviser.

Qualifications

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by the Company since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to the Company's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the Company's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in California, Idaho, Oregon, Utah, Wyoming, and FERC dockets.

Purpose of Testimony and Recommendation

Q. What is the purpose of your testimony?

A. My testimony supports the Company's proposal to create Electric Service Schedule

No. 137 – Net Billing Services, ("Schedule 137"), under which customers would be compensated for generation in excess of their own load that is exported to the Company's system based upon the Company's avoided cost. I address three primary issues. First, I describe the elements, methodology, and calculation of the export credit value. Second, to better ensure compensation is consistent with exported volumes, I describe on-peak and off-peak time of export definitions that differentiate between periods of higher and lower avoided costs; and finally, I address how the export credit will be updated going forward.

Q. Have you prepared a summary of the proposed export credit values?

A. Yes. A summary of the export credit results is shown in Exhibit RMP___(DJM-1). My calculations support an average annual export credit of $15.26 per megawatt-hour ("MWh").

Export Credit Methodology

Q. What elements are included in the $15.26/MWh value of the customer generation export credit?

A. The export credit includes the following elements related to the impact of exported energy on the Company's system dispatch:

- **Avoided Energy Cost:** when customer generation is exported to the grid, the Company can reduce the output of its generation resources or reduce the volume of its market purchases. The resulting reduction in fuel expense and purchased power cost is the avoided energy cost.
- **Avoided Line Losses:** line losses are the difference between the total generation injected into the grid, and the total metered volume at customer sites.

As a result, a kilowatt-hour produced by a generator is not equivalent to a kilowatt-hour delivered to a customer. The Company's avoided energy costs are typically measured based on generation and market purchases at transmission voltages, while the metered volumes for residential generation exports are measured at the secondary voltage level. It is appropriate to adjust exported energy values from customer generation to account for the resulting avoided line losses.

- **Integration Cost:** The Company uses flexible resources to accommodate fluctuations in the load and resource balance of its system attributable to load, wind, solar, and other non-variable energy resources that are not under the Company's control. Integration costs represent the cost of holding reserves with flexible resources to reliably maintain the load and resource balance.

Q. How does the Company propose calculating exported energy costs?

A. The Commission has approved the Proxy/Partial Displacement Revenue Requirement Methodology ("PDDRR") for determining avoided costs for standard qualifying facility ("QF") resources up to at least 3 MW in nameplate capacity.[1] Under the PDDRR Methodology, avoided energy costs are calculated using PacifiCorp's Generation and Regulation Initiative Decision Tool ("GRID") while avoided capacity costs are calculated based on deferrable resources in PacifiCorp's most recently filed Integrated Resource Plan ("IRP") preferred portfolio. The proposed export credit program is secondary to a customer's own use so it is considered non-firm and no future

[1] *Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities*, Docket No. 17-035-T07 (Jan. 23, 2018).

capacity resources would be deferred.

Q. Why is non-firm pricing appropriate?

A. Firm contracts would include credit terms, security deposits, performance guarantees, liquidated damages, default provisions, and termination rights that are not found in the Schedule 137 tariff. Those contractual terms protect the utility and non-participating customers from non-performance and are essential to mitigating the risks associated with long-term contracts. Since customers are under no obligation to deliver any energy and will offset their own load first, non-firm valuations are appropriate. If a customer desires a firm or longer term contractual arrangement for their generation, they have the option of self-certifying as a QF and obtaining a contract under the applicable QF tariff.

Q. Do monthly avoided energy costs reported by the GRID model results provide sufficient granularity for determining an export credit?

A. No. To more accurately value export energy, the Company is proposing distinct on-peak and off-peak rates, as discussed later in my testimony. While the GRID model has hourly granularity, the results are confidential and can also reflect changes that span multiple hours.

Q. What hourly price shaping methodology do you propose?

A. To create an hourly shape, the Company proposes using the results of Energy Imbalance Market ("EIM") operations. Specifically, the Company proposes using 15-minute PacifiCorp east ("PACE") EIM load aggregation point ("LAP") prices for the most recent 36 month period, in this instance, the 36 months ending October 2019. The historical data is used to create a market price "scalar" based on the average market prices in a month during a given hour, relative to the average market price in that month during all hours. For instance, if the average market price during hour-ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour-ending 10 in May would be 90 percent.[2] The average of the 24 hourly scalars for a given month is always 100 percent.

Q. What are the current inputs to the PDDRR methodology used to determine the value of exports?

A. On a quarterly basis, the Company submits an avoided cost inputs compliance filing with details on the current inputs to the PDDRR methodology. The most recent filing occurred on January 10, 2020 in Docket No. 19-035-18.[3] At this time, the PDDRR methodology primarily reflects assumptions from PacifiCorp's 2019 IRP. Since the compliance filing, Company's GRID model has been updated to incorporate market prices from the December 31, 2019 Official Forward Price Curve and changes to executed contracts, as one 80 MW solar contract has been executed and four wind and solar contracts totaling 38 MW have been terminated. Consistent with the methodology adopted by the Commission for published QF prices under Schedule 37, the export credit value is calculated without including a queue of potential QF resources that have requested pricing and are negotiating contracts. While the Company identified a non-routine methodology change in its January 10, 2020 compliance filing that has not yet taken effect, the proposed change does not impact the results in the proposed study period of 2021.

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[2] $18/MWh / $20/MWh = 90 percent.

[3] *Rocky Mountain Power's 2019 Avoided Cost Input Changes Quarterly Compliance Filing.* Docket No. 19-035-18. *Available at*: https://psc.utah.gov/2019/04/30/docket-no-19-035-18/.

Q. What are the specifications of the export credit resource modeled within GRID?

A. The export profile is based on the Company's Load Research Data from the 12 months ending September 2019. The assumed delivery point within the GRID model is split between the three transmission areas which contain Utah load: Clover, Utah North, and Utah South. The split is calculated based on the proportion of weather-normalized actual Utah retail load in these areas in the semi-annual results of operations from the 12 months ending June 2019, with more than 90 percent of the total located in Utah North, 8 percent in Utah South, and 1 percent in Clover. The average export profile has a 14 percent capacity factor based on the maximum hourly export of 4.6 kilowatts. To ensure that the results reflect values appropriate to Net Billing program as a whole, and to account for the granularity of the GRID model, which might not register changes measured in kilowatts, the export credit value was calculated based on the export profile average of approximately 9,000 customers, which is approximately 50,000 megawatt-hours annually, or under six average megawatts.

Q. What is the proposed exported energy value for customer generators?

A. The GRID model value of the export profile during the proposed rate effective period of 12 months ending December 2021 is $14.45/ MWh. Values are further distinguished by season and on-peak/off-peak period, as discussed later on in my testimony.

Q. Regarding the proposed rate effective period, will this affect customers' retail rates?

A. No. The Company is not proposing to make any changes to customers' retail rates. The proposed rate effective period that I discuss in my testimony deals only with the Company's proposed export credit rate.

Q. How does the Company propose calculating avoided line losses?

A. The line losses incorporated in the Company's current rates are from its 2009 Analysis of System Losses for Utah. That study identified line losses in Utah specific to the following interconnection levels:

- Transmission: 4.53 percent
- Primary: 6.635 percent
- Secondary: 9.322 percent

The Company has used the results from power flow studies to calculate a marginal loss by load level and then fitted it to a 12 month by 24-hour profile for each of the interconnection levels referenced above. The result is an estimate of avoided line losses that can be differentiated by time of day and can be used to determine specific on-peak and off-peak values.

Q. What level of avoided line losses are included in the export credit calculation?

A. 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.

Q. What is the proposed value of avoided line losses?

A. The average value of avoided line losses from the export profile during the rate effective period of 12 months ending December 2021 is $0.96/MWh. Values are further distinguished by season and on-peak/off-peak period, as discussed later on in my testimony.

Q. What integration cost does the Company propose incorporating in the export credit value?

A. The Company anticipates that most of the resources exporting under the proposed program will be solar generators. The Company's 2019 IRP includes a Flexible Reserve Study,[4] which identifies the amount of flexible capacity required to compensate for variations in load and resources, as well as the cost of holding that capacity available. The 2019 IRP identified a solar integration cost of $0.15/MWh in 2021 and the Company proposes that this value be included in the export credit calculation.[5]

On-Peak and Off-Peak Definitions

Q. What is the purpose of distinguishing between on-peak and off-peak hours?

A. The Company's marginal costs vary significantly over the course of the day. In addition, a customer's export output will also vary over the course of the day. If a customer exports more during a part of the day with a relatively high value, it will provide greater benefits than if that customer exports during a part of the day with a relatively low value. Distinguishing periods with different value ensures that exporting customers receive appropriate compensation consistent with the value they provide to the system. This also provides customers with an incentive to adjust their load profiles to make better use of their own generation resources, as their avoided purchases still avoid the full cost-based retail rate.

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[4] 2019 Integrated Resource Plan. Volume II, Appendix F: Flexible Reserve Study, *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf.
[5] *Ibid*. Figure F.15.

Q. Are any on-peak and off-peak definitions currently in place that are applicable to residential customers?

A. Yes. Schedule 2 includes optional time of day rates for residential service. The definitions in Schedule 2 are as follows:

On-Peak:

- Summer (May-September): 1:00 P.M. to 8:00 P.M., Monday through Friday, except holidays.

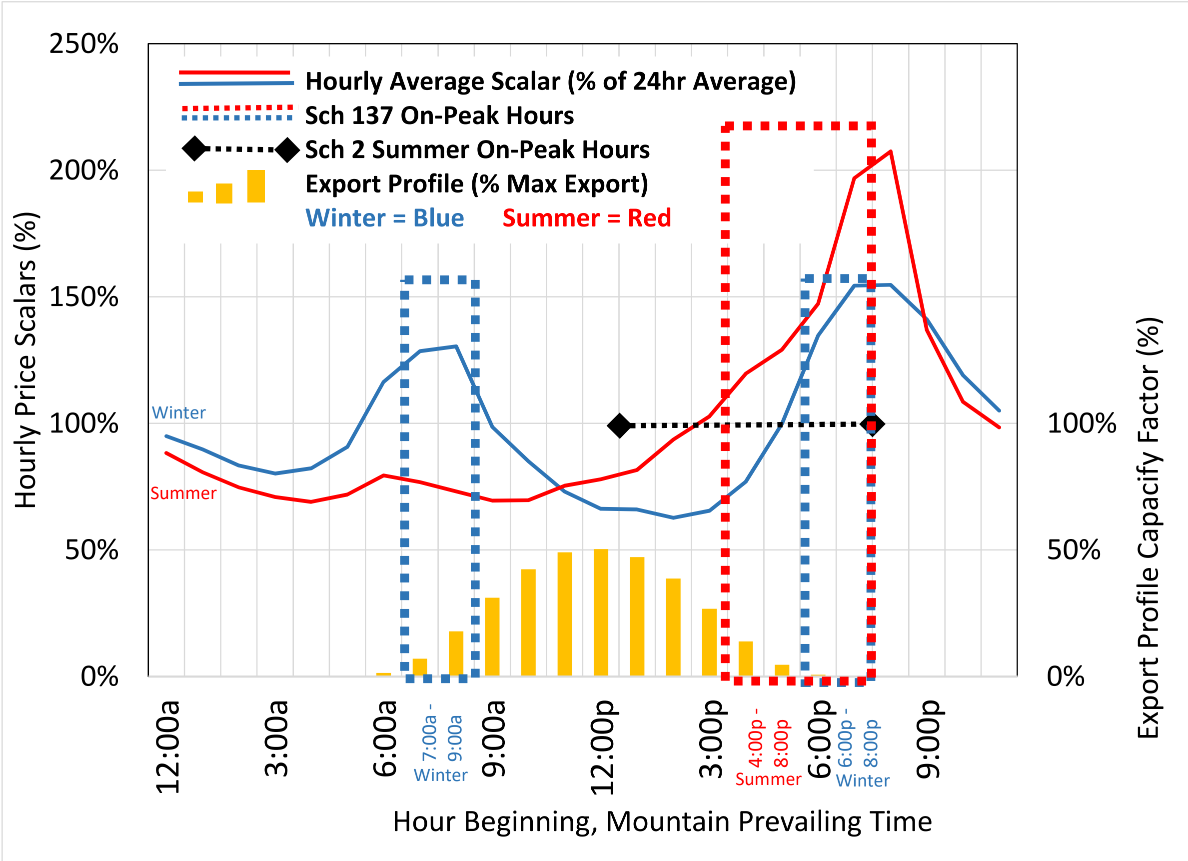
Off-Peak:

- All other hours, including the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day.

Q. Do the on-peak and off-peak definitions in Schedule 2 align well with the Company's marginal costs?

A. Not entirely. The average EIM scalars by hour show a wide variation in prices across the day, as shown in Figure 1. A portion of the on-peak hours under Schedule 2 have prices that are below average.

Figure 1: Hourly Price Scalars and Export Profile



Q. What on-peak and off-peak definitions do you propose?

A. Ideally the value within each period should be as uniform as possible, so that whenever a customer exports in a given period, the benefits are similar. At the same time, good ratemaking principles suggest that the on-peak and off-peak definitions be easy for customers to understand and align with existing programs. With that in mind, the Company proposes that the on-peak definition end at 8:00 p.m. consistent with the existing time of use definition. This end time also encompasses the vast majority of the export profile, which is predominantly composed of solar resources. With that bound in place, the top four price hours during the summer all occur between 4:00 p.m. to 8:00 p.m. Mountain Prevailing Time ("MPT"). In the winter, the top four price hours are split between the morning and the evening, and include 7:00 a.m. to 9:00 a.m. and 6:00 p.m. to 8:00 p.m. MPT. To maintain consistency with Schedule 2, on-peak hours also only apply to Monday through Friday, and do not include holidays. All hours other than on-peak hours are considered off-peak hours.

Q. Are all of the export credit elements differentiated between on-peak and off-peak periods?

A. Yes. Energy and line losses are readily differentiated as the underlying source data has hourly granularity. Integration costs are based on annual average values that reflect the cost of holding back flexible resources that could otherwise be used to serve customer load or support wholesale sales. Higher hourly energy prices imply higher costs for integration, so this element has been differentiated using the same ratios as the energy element.

Q. Are you proposing a change to the summer and winter season definitions, relative to the Schedule 2 definitions?

A. Yes. The proposed summer season definition spans June through September, whereas the Schedule 2 summer season definition also includes May. The hourly price scalars for the month of May are better aligned 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. MPT. In addition, while the Company occasionally experiences high peak-producing temperatures in the end of June or beginning of September that can lead to high prices, this is not true of May. As a result, the proposed definition results in higher prices that provide a stronger price signal during the summer periods when the Company's resource needs and avoided costs are highest.

Q. What are the proposed export credit values?

A. Details on the proposed export credit values by season and by on-peak/off-peak are shown in Exhibit RMP___(DJM-1).

Updating Export Credit Rates

Q. Will a customer's export credit be fixed or will it be updated?

A. The Company proposes to update the export credit annually. This will ensure that the export credit payments continue to be consistent with the Company's avoided cost and that they are consistent with the non-firm nature of the output. This will also allow all customers participating under Schedule No. 137 – Net Billing Services to receive the same export credit rates, reducing the administrative complexity of assorted vintages of export credit rates and on-peak/off-peak definitions.

Q. What factors drive the timing of an annual export credit update?

A. Avoided costs under Schedule 37 are updated annually, typically on April 30th with a July 1st effective date. Since avoided energy costs are calculated using the same methodology and model as Schedule 37 and represent the majority of the export credit value, it would be reasonable to update the export credit rates at the same time. Data for avoided line losses, integration costs, or other inputs would be updated to reflect the most recent information available for inclusion in the annual update. Therefore the Company proposes to file an update to export credit values annually on April 30th with a July 1st effective date.

Q. Where would the cost of the export credit be booked and how would it be treated for regulatory purposes?

A. The Company recommends that export credit payments continue to be recorded in

FERC Account 555 and tracked in the energy balancing account. Excess energy from customer owned generation is fed into the grid offsetting some of the need for energy from other sources. Customers that produce more energy than they use would receive a credit on their bill at the export credit rate for any excess energy supplied to the grid. This credit would be treated just like any other purchased power expense by debiting FERC Account 555 with an offsetting credit to the customer's bill.

Conclusion

Q. Please summarize your recommendations for the Commission.

A. The Company recommends that the Commission set the export credit at $15.26 / MWH for calendar year 2021. This value should be differentiated by on-peak / off-peak and summer / winter periods that reflect higher and lower avoided costs values, with on-peak defined in the summer as 4:00 p.m. to 8:00 p.m., MPT, and in the winter as 7:00 a.m. to 9:00 a.m. and 6:00 p.m. to 8:00 p.m., MPT. On-peak days will be limited to Monday through Friday, not including holidays, and all other hours will be considered off-peak. Finally, I recommend that the export credit be updated annually with a July 1st effective date.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Daniel J. MacNeil

Proposed Schedule 137 Customer Generation Meter Fee

February 2020

PacifiCorp
State of Utah
Export Credit Summary by Element

Month	On-Peak Energy $/MWh	On-Peak Losses $/MWh	On-Peak Integration $/MWh	On-Peak Total $/MWh	Off-Peak Energy $/MWh	Off-Peak Losses $/MWh	Off-Peak Integration $/MWh	Off-Peak Total $/MWh	Average* Total $/MWh
1/1/2021	$24.82	$1.64	($0.27)	$26.19	$15.27	$1.01	($0.16)	$16.11	$16.17
2/1/2021	$36.62	$1.75	($0.39)	$37.98	$15.70	$0.75	($0.17)	$16.28	$16.50
3/1/2021	$30.09	$1.55	($0.32)	$31.32	$12.83	$0.66	($0.14)	$13.36	$13.96
4/1/2021	$22.45	$1.06	($0.24)	$23.28	$9.95	$0.47	($0.11)	$10.31	$11.07
5/1/2021	$16.43	$0.93	($0.18)	$17.19	$11.39	$0.65	($0.12)	$11.92	$12.25
6/1/2021	$19.82	$1.34	($0.21)	$20.95	$13.14	$0.89	($0.14)	$13.89	$14.26
7/1/2021	$30.05	$2.88	($0.32)	$32.60	$19.63	$1.88	($0.21)	$21.30	$21.76
8/1/2021	$33.21	$2.51	($0.36)	$35.36	$17.14	$1.29	($0.18)	$18.25	$18.87
9/1/2021	$19.72	$1.33	($0.21)	$20.83	$14.93	$1.01	($0.16)	$15.77	$15.93
10/1/2021	$25.44	$1.52	($0.27)	$26.69	$13.11	$0.78	($0.14)	$13.75	$13.89
11/1/2021	$22.55	$1.40	($0.24)	$23.71	$13.73	$0.86	($0.15)	$14.44	$14.67
12/1/2021	$26.46	$1.80	($0.28)	$27.98	$16.56	$1.13	($0.18)	$17.51	$17.61
Annual*	$22.90	$1.48	($0.25)	$24.13	$14.11	$0.94	($0.15)	$14.90	$15.26
Summer*	$24.66	$1.89	($0.26)	**$26.29**	$16.01	$1.24	($0.17)	**$17.08**	$17.44
Winter*	$21.49	$1.15	($0.23)	**$22.41**	$12.67	$0.71	($0.14)	**$13.25**	$13.60

Definitions:

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

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

All times are in Mountain Time

* Average values reflect delivery based on historical average export profile

CERTIFICATE OF SERVICE

I hereby certify that on February 3, 2020, a true and correct copy of Rocky Mountain Power's **Direct Testimony** in Docket No. 17-035-61 was served by email and overnight delivery on the following Parties:

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