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UTILITIES COMMISSION

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

February 8, 2024

VIA ELECTRONIC DELIVERY

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd
Building 8 Suite 201A
Boise, ID 83714

**RE: CASE NO. PAC-E-23-17
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO COMPLETE THE STUDY REVIEW PHASE OF THE STUDY OF THE COSTS AND BENEFITS OF ON-SITE CUSTOMER GENERATION**

Attention: Commission Secretary

Please find attached Rocky Mountain Power's electronic filing of its on-site generation study supplement (Study Supplement) to its on-site generation study which was filed on June 29th, 2023.

The Study Supplement is intended to replace the previously submitted study in its entirety. The company is submitting the Study Supplement in response to a request from commission staff. The supplement includes revisions and additions that were made in collaboration with commission staff.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle Steward
Senior Vice President, Regulation and Customer & Community Solutions

Enclosures
CC: Service List – Case No. PAC-E-23-17

Rocky Mountain Power | Pacific Power

SUPPLEMENT TO ROCKY MOUNTAIN POWER'S ON-SITE GENERATION STUDY

PAC-E-19-08 Net Metering IPUC Order No. 34753

February 2024

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Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
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Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
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18	Avoided Environmental Costs and Other Benefits	Quantify the possible net value of Renewable Energy Credit sales produced by net metering exported energy.	9.4
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21	Recovering Export Credit Rates in the ECAM	Quantify the current annual amount of the net metering costs allocated to each class.	10.2
22	Recovering Export Credit Rates in the ECAM	Present and explain how these costs have been allocated and recovered between rate classes for the past five years.	10.2
23	Recovering Export Credit Rates in the ECAM	Quantify these annual costs under the assumptions that the Export Credit Rate is the retail rate, 7.4 cents/kWh, 5 cents/kWh, or 2.23 cents/kWh.	10.3

Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
24	Recovering Export Credit Rates in the ECAM	Analyze how these costs would be allocated and recovered by rate class through the Company's proposed ECAM method going forward.	10.3
25	Schedule 136 Implementation Issues (Billing Structure)	Explain if and how seasonal and time-of-delivery price differences will be used to help align customer generated exported energy with the Company's system needs.	11.1
26	Schedule 136 Implementation Issues (Billing Structure)	Explain if and how using more granular time periods for differentiating energy and capacity credits could be used to more closely align customer-generated exports with the Company's system needs.	11.1
27	Schedule 136 Implementation Issues (Billing Structure)	Explain how potential customer-generators and on-site generation system installers will have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system	11.1
28	Schedule 136 Implementation Issues (Billing Structure)	Explain how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.	11.1
29	Schedule 136 Implementation Issues (Export Credit Expiration)	Quantify the magnitude, duration, and value of accumulated export credits as of August 1, 2020.	11.2
30	Schedule 136 Implementation Issues (Export Credit Expiration)	Quantify the impact to customers of a 2-year, 5-year, and 10-year expiration periods.	11.2
31	Schedule 136 Implementation Issues (Export Credit Expiration)	Explain the need for credits to expire. a. Show how the Company does or does not benefit from the expiration of customer export credits. b. Show how non net bill customers are harmed or benefited from the expiration of customers export credits.	11.2
32	Schedule 136 Implementation Issues (Frequency of Export Credit Updates)	Quantify the impact of biennial updates as compared to annual updates of the Export Credit Rate by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle (two years), and two IRP cycles (four years).	11.3

Item Number	Subject	Order No. 34753 – Attachment A: Scope of Rocky Mountain Power's On-Site Generation Study	Location in Study
33	Smart Inverter Study	Explain the key aspects of the Company's Utah smart inverter policy and quantify the benefits of applying that policy in its Idaho service territory, in particular, the potential benefits of reactive power control.	12.0

Glossary

90/110 performance band – A PURPA generator's energy deliveries plus or minus 10% from its forecasted performance.

Automated Meter Infrastructure (AMI) – Integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

Distributed Energy Resource (DER) – A small-scale supply or demand resource that is usually situated near sites of electricity use.

Energy Imbalance Market ("EIM") – The EIM automatically balances demand every five minutes with the lowest cost energy available across the participating grids.

Export Credit Rate (ECR) – The total credit to the customer once a customer's generation is netted by either real-time billing or interval netting.

Flexible Reserve Study (FRS) – Estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards as well as the incremental cost of this regulation reserve.

Instantaneous Billing – Method of calculating customer-generator billing where the customer's financial credit for exports and the customer's retail charges are calculated separately and the net result is either charged or credited to the customer.

Integrated Resource Plan (IRP) – The IRP is a comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric service to all our customers. Developed with involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders the IRP focuses on the first 10 years of a 20-year planning period and includes the preferred portfolio of supply-side and demand-side resources to meet this need. PacifiCorp prepares its integrated resource plan on a biennial schedule, filing its plan with state utility commissions during each odd numbered year.

Integration Costs – The additional expense when variable energy resources are added to a portfolio. Typically includes costs related to the uncertainty and variation in variable energy resource output from moment to moment. For distributed resources, integration costs could potentially include equipment and/or operational changes to manage impacts on the distribution system.

Interval Netting – Method of calculating customer billing where the total electricity consumed and generated is calculated for a given interval and the output of that calculation is included on a customer's bill.

Line Losses – Loss of electricity due to the resistance of the conductor, or line, against the flow of the current, or electricity.

Loss of Load Probability (“LOLP”) – Likelihood of a risk of loss of load event where system load and/or reserve obligations could not be met with available resources.

Net Billing – As defined by Electric Service Schedule 136, charges for all electricity supplied by the Company and netted by the export credit for the electricity generated by an eligible customer and fed back to the electric grid over the applicable billing period. Net billing differs from net metering because net billing customers do not get a credit in kWh but instead all net energy exports are credited to the customer at the exported customer-generated energy credit rate.

Net Metering – As defined by Electric Service Schedule 135, the difference between the electricity supplied by the Company and the electricity generated by an eligible customer and fed back to the grid over the applicable billing period. Net metering may also refer to on-site generation or a distributed energy resource in general.

The Public Utility Regulatory Policies Act of 1978 (“PURPA”) – Enacted following the energy crisis of the 1970s to encourage cogeneration and renewable resources and promote competition for electric generation.

Qualifying Facility (“QF”) – a generation facility that meets certain ownership, operating, and other criteria established by the Federal Energy Regulatory Commission (“FERC”) according to the Public Utility Regulatory Policies Act of 1978 (“PURPA”)

Renewable Energy Certificates (“RECs”) – The property rights to the environmental, social, and other non-power attributes of renewable electricity generation. RECs are issued when one megawatt-hour (MWh) of electricity is generated and delivered to the electricity grid from a renewable energy resource.

Surrogate Avoided Resource ("SAR") Methodology – Method for determining avoided costs for standard qualifying facility resources up to at least 100 kW in nameplate capacity. Under the SAR Methodology, avoided energy costs reflect forecast prices for natural gas and the assumed heat rate of a combined cycle combustion turbine. Monthly weighting factors are used to differentiate avoided costs by month, and an adjustment of 85 percent is applied to non-firm resources.

1.0 Executive Summary

Rocky Mountain Power, a division of PacifiCorp ("PacifiCorp" or the "Company") presents this study ("Study") to evaluate methods, inputs, and assumptions for valuing on-site generation that is exported to the grid. The Idaho Public Utilities Commission ("Commission") approved the scope of this study ("Study Scope") of on-site generation on August 26, 2020.[1]

The Study provides the Commission and stakeholders with the information needed to consider changes to the export credit rate ("ECR") for on-site customer generators in the future. The purpose of this Study is not to propose a specific ECR at this time but to initiate a review and obtain feedback on potential considerations for valuing an ECR.

The Study gives a snapshot of its current approximately 2,200 on-site customer generation customers in Idaho. Data for modeling different components of the ECR was based on Utah customers in the same climate zone as Idaho customers.

The effects of netting imports monthly, hourly, and instantaneously were studied to show the effects for each scenario. As guided by the Commission's Study Scope, the avoided cost of exported energy was calculated using the same price assumptions as the Company's most recently acknowledged integrated resource plan ("IRP") and the capacity value of exported energy was analyzed using the loss of load probability ("LOLP") study. The avoided capacity value of on-site generators was modeled during PacifiCorp's highest risk-of-loss-of-load-event hours to evaluate potential contribution of on-site generation during the grid's most strained hours. Different export credit scenarios were analyzed to show the annual export costs at various ECRs. The Study concludes by looking at the different implementation issues for an ECR including how different customers would be affected by expired credits and the effects of updating the ECR at different frequencies.

2.0 Introduction

2.1 Current Net Metering Summary

As of December 31, 2022, there are 2,196 on-site generating customers connected to PacifiCorp's system in Idaho. The majority of those customers are residential using solar photovoltaic ("PV") systems. There are also 61 wind generation customers and five customers with a mix of electricity sources or with hydro generators.

[1] *In the Matter of the Application of Rocky Mountain Power to Close the Net Metering Program to New Service & Implement a Net Billing Program to Compensate Customer-Generators for Exported Generation.* Case No. PAC-E-19-08, Order No. 34753.

Table 2.1: Idaho On-Site Generation Customer Count as of 12/31/2022

Customer Type	Solar PV	Wind	Mixed/ Other	Total
Residential	2,055	54	5	2,114
Small Commercial	63	5	-	68
Large Commercial	8	2	-	10
Irrigation	4	-	-	4
Total	**2,130**	**61**	**5**	**2,196**

Net metering customers participate in the Company's customer generation programs through Schedules 135 or 136. Residential and general service customers taking service on Schedules 1, 23, 23A, or 36 must not have a generating capacity greater than 25 kilowatts (kV). All other customers are limited to a generating capacity of 100 kW. Schedule 135 closed to new applicants as of October 2, 2020. The average size of a residential customer's solar PV system is 8.1 kW, as of December 31, 2022.[2]

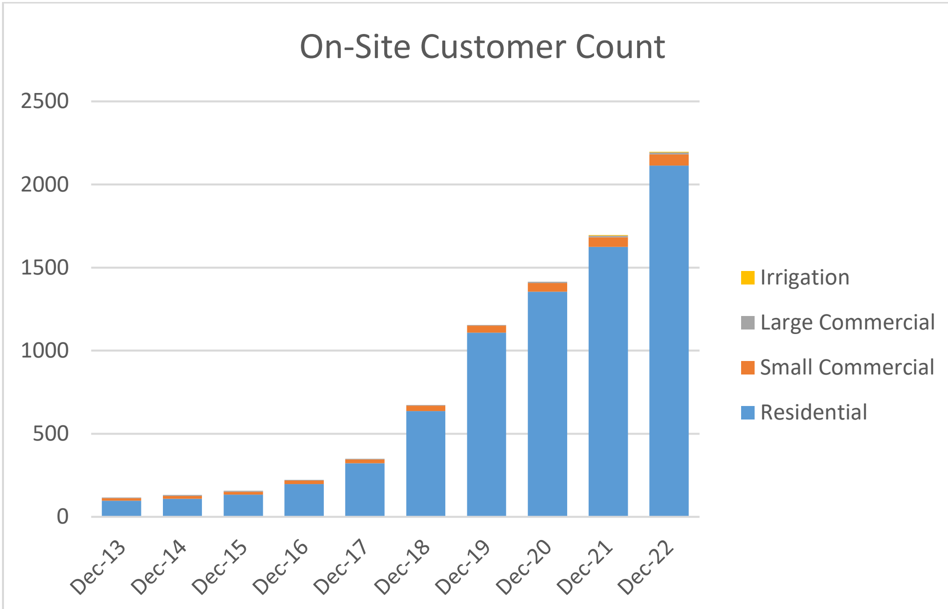
Table 2.2: Average Size of On-Site Generation Customer's System

Customer Type	Solar PV kW (average)	Wind kW (average)	Mixed/Other kW (average)
Residential	8.1	3.75	12.35
Small Commercial	16.95	9.44	-
Large Commercial	44.74	2.4	-
Irrigation	21.58	-	-
Weighted Average	**8.51**	**4.17**	**12.35**

On-site generation customer growth has increased steadily over the last 10 years with an annual average growth rate of 40%. While customer growth has moderated slightly during the last 3 years in percentage terms, 2022 saw the most on-site customers connecting to the system with a total of 500 new customers added.

[2] For more detail on the customer size, generation type, and customer system size, see the system size tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022

Figure 2.1: On-Site Generation Customer Adoption



2.2 Regulatory History

PacifiCorp began offering Electric Service Schedule 135 - Net Metering Service, in 2003, as approved by Order No. 29260 in Case No. PAC-E-03-4. The case was initiated following a petition by the NW Energy Coalition which requested a net metering schedule in Idaho following approval of net metering schedules for Idaho Power Company and Avista. In that case, PacifiCorp proposed Schedule 135, which was patterned from Idaho Power's net metering Schedule 84.

Schedule 135, as approved by Order No. 29260, limited participation on Schedule 135 to no more than 25 kilowatts for customers taking service on Schedules 1, 36, 23, or 23A and to 100 kilowatts for all other customers. Customers taking service on Schedules 1, 36, 23 or 23A were to be credited for excess net energy at the customer's standard service rate and all other customers would be credited net excess energy at a rate that equals 85 percent of the monthly weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Electricity Price Index (Dow Jones Mid-C Index).

On June 14, 2019, PacifiCorp submitted an application to close Electric Service Schedule 135 and to implement a net billing program to compensate customer-generators for exported generation.[3] On August 26, 2020, the Idaho Public Utilities Commission issued Order No. 34753 which required this on-site generation study to be completed. On October 2, 2020, the Idaho Public Utilities Commission issued Order No. 34798 initiating Electric Service Schedule 136 - Net

[3] *See In the Matter of the Application of Rocky Mountain Power to Close the Net Metering Program to New Service & Implement a Net Billing Program to Compensate Customer-Generators for Exported Generation.* Case No. PAC-E-19-08

Billing Service. Order No. 34798 also adopted Order No. 34752, which granted existing Electric Service Schedule 135 customers grandfathered status for a period of 25 years.

3.0 Netting Period

3.1 Summary of Instantaneous, Monthly, and Hourly Billing

There are three different methods of "netting" that may be used to calculate the amount of electricity that a customer consumes and exports: instantaneous, hourly, and monthly. In a "real time" or "instantaneous" calculation, the metered quantities of electricity that are exported to the grid form the customer's generator and that are taken from the grid and used are measured separately. With instantaneous netting, all of the consumption from the electric grid is measured and charged the retail rate and all exports to the electric grid are also measured and credited to the customer.

Interval netting, on the other hand, does not calculate instantaneously but instead calculates the total net electricity consumed or generated over the certain interval or period of time. While on first look it may appear that instantaneous and interval netting would result in similar outcomes, this is not the case. To the extent a customer was using power from the electric grid during part of an hour, and exporting during the rest of an hour, hourly netting would wash out these two amounts, relative to instantaneous netting. With monthly netting, even larger amounts of consumption and exports can be offset, as the customer's consumption may be days or weeks earlier or later than their exports.

Using an interval over which exports and imports are netted masks the actual timing of energy delivered to the customer and energy exported from the customer and distorts the service that Rocky Mountain Power provides. One benefit of a net billing program without interval netting is that it encourages customer-generators to line up their usage with their generation output. This can benefit other non-participating customers by accurately taking into account the load that the customers with generation draw from the system. Netting over an interval period, such as 15 minutes or an hour, provides less of an incentive for customer-generators to match usage with generation. With the scale of customer generation that has been adopted in the Company' service territory, encouraging loads to line up with intermittent generation has never been more important. When a cloud rolls by an area where there is a lot of customer generation, their energy generation will suddenly drop, and the Company must provide the power needed. Indeed, every fraction of a second the Company must serve the load requirements of its customers as loads fluctuate in real time. Strongly encouraging customer generators to line up their generation with load as a net billing program does, creates a greater opportunity for customer-generators to benefit the system.

3.2 Class Revenue Requirement

The tables and analysis below address Study Scope Item 1.

Study Scope Item 1

Calculate the class revenue requirement if each of the existing customer-generators netted their energy exports: a. Monthly b. Hourly c. Instantaneously

To estimate the revenue requirement impact to revenue for each of the types of netting required for the Study, the Company examined the monthly billing and metering data from customer-generators in 2022 from which the Company could determine values for the monthly netting and instantaneous netting scenarios. The Company did not include irrigation customer-generators, because there were only two irrigation customers with on-site generation, and they did not have a full 12 months of revenue in 2022.

Automated meter infrastructure ("AMI") installations are being finalized during the second quarter of 2023 and the Company does yet not have enough hourly profile data available for customer-generators in Idaho for hourly loads. Instead, the Company used proxy profile data from its customer-generators in northern Utah which are in the same climate zone as the Company's Idaho service territory. To estimate hourly netting values, the monthly percentage differences in hourly as compared to instantaneous netting from the Northern Utah dataset were applied to metered data from Idaho customer-generators. The following table 3.1 shows the exported energy volumes under each netting scenario in total and also expressed as a percentage of generation:

Table 3.1: Comparison of Generation to Exports under Different Netting Scenarios

Export and Generation (kWh)	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Generation
Residential Sch 1	2,111,780	8,062,620	8,554,724	16,422,970
Residential Sch 36	551,492	2,058,027	2,182,649	4,124,398
General Service Sch 23	244,599	534,099	565,335	1,512,638
General Service Sch 6	58,760	116,414	123,320	522,963
Total	**2,966,631**	**10,771,161**	**11,426,028**	**22,582,969**

Export % of Generation	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Generation
Residential Sch 1	13%	49%	52%	100%
Residential Sch 36	13%	50%	53%	100%
General Service Sch 23	16%	35%	37%	100%
General Service Sch 6	11%	22%	24%	100%
Total	**13%**	**48%**	**51%**	**100%**

Table 3.1 shows that about half (51%) of generation is exported to the grid. If exports are netted on an hourly basis, exports are a little less at about 48% of generation. Using monthly netting, dramatically reduces the quantity of exported energy to being only about 13% of generation. To estimate the revenue impact by customer class of different netting scenarios, the Company estimated the change in revenue from traditional net metering. Assuming a generic 3¢ per kWh export credit, the Company estimates the following revenue changes from traditional net metering for the different netting scenarios:

Table 3.2: Revenue Requirement Changes from Traditional Net Metering

Net Revenue	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Traditional Net Metering
Residential Sch 1	$1,253,784	$1,716,364	$1,756,739	$1,090,937
Residential Sch 36	$384,917	$462,434	$468,933	$333,476
General Service Sch 23	$156,402	$172,883	$174,728	$141,635
General Service Sch 6	$296,204	$296,925	$297,011	$295,469
Net Revenue (All Schedules)	$2,091,307	$2,648,606	$2,697,411	$1,861,517
Difference from Traditional Net Metering	-$229,791	-$787,089	-$835,895	-

Based on Table 3.2 above, monthly netting would result in a $230k increase to revenue when compared with traditional net metering, meaning that an additional $230k is recovered from customer generators and not required from other customers. Hourly netting would see a larger $787k increase and instantaneous netting would see a $836k increase in revenue when compared with traditional net metering.

3.3 Class Export Payment

The Study Scope also required the Company to calculate the export credits for each customer class at different intervals.

Study Scope Item 2

Calculate the total class export credit payments if each of the existing customer-generators net their energy exports: a. Monthly b. Hourly c. Instantaneously

Using the same assumptions as the revenue analysis above, the Company estimates the following class export payments for the different netting scenarios.

Table 3.3: Export Payments by Class

Export Credit Payments	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting
Residential Sch 1	$63,353	$241,879	$256,642
Residential Sch 36	$16,545	$61,741	$65,479
General Service Sch 23	$7,338	$16,023	$16,960
General Service Sch 6	$1,763	$3,492	$3,700
Total	**$88,999**	**$323,135**	**$342,781**

3.4 Bill Impacts

The Study Scope required the Company to calculate the bill impacts to existing customer-generators.

Study Scope Item 3

Analyze bill impacts to existing customer-generators, stratified by usage, if energy exports are netted: a. Monthly b. Hourly c. Instantaneously

Using the same assumptions from the previous sections, the Company estimates the following average bills for the different netting scenarios:

Table 3.4: Bill Impacts by Class

Average Bill	a. Monthly Netting	b. Hourly Netting	c. Instantaneous Netting	d. Traditional Net Metering
0 - 500 kWh	$14.49	$44.44	$47.28	-$2.66
501 - 1,000 kWh	$77.92	$97.97	$99.38	$77.49
1,000 - 1,500 kWh	$128.66	$144.73	$145.83	$128.55
1,500 - 2,000 kWh	$179.33	$193.98	$194.99	$179.33
2,000 - 3,000 kWh	$247.76	$261.38	$262.37	$247.76
3,000 - 5,000 kWh	$372.39	$383.30	$384.07	$372.39
5,000 kWh - 10,000 kWh	$624.67	$632.67	$633.28	$624.67
10,001 kWh+	$2,553.63	$2,559.70	$2,560.04	$2,553.63
Average	**$91.18**	**$115.48**	**$117.61**	**$81.16**

3. 5 Administrative Costs

Instantaneous billing provides administrative benefits compared to interval netting. Under instantaneous netting, all exported energy sent to the grid is measured and all energy delivered from the grid to the customer to be used at their site is measured. These are two simple quantities of energy that the meter shows each month. Under interval netting, such as hour interval netting, these measurements must be examined and netted for every hour. Using the meters for exported and delivered energy instead of relying upon profile data (for example hour-by-hour usage measurements in a month) to bill customers is less administratively burdensome for the Company. Without netting, the Company's meters simply record energy delivered and energy exported and send those amounts to the Company's billing system to calculate a bill for the customer. While the Company has automated much of the process for billing customers based upon 15-minute intervals for customer generators in Utah, there still is some backend manual work that is required to accurately bill customers. 15-minute interval netting requires much more data for each meter which on average includes 2,920 reads for each monthly billing period. Most of the time, there are no issues with this data, but when there is, Company employees must resolve it. Some of the issues that may require employee attention include:

- Meter aggregations require manual calculation using a billing calculation sheet. The Company estimates 0.25 – 0.50 hours per month aggregating meter data depending on number of meters involved.
- Interval data issues such as from gaps in data or when meters are exchanged also require employee time. It is hard to estimate the time spent on missing data as it only occasionally happens and now AMI exchanges are mostly complete in Idaho. Going forward, meter exchanges will happen less frequently. Assuming a one percent failure

of billings each year and 0.5-1.0 hours to resolve for each 100 customers in net billing, then the following time requirement is estimated:

100 customers x 12 billings = 1200 x 1% = 12 accounts x 0.5 – 1.0 hour = 6 - 12 hours annually

At the current volume of 2,200 customer-generators, this would be about 132 to 264 hours of activity per year for the Company. In addition, 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 or hour 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 interval period.

4.0 Export Credit Rate

The ECR determines the total credit to the customer once a customer's generation is netted by either instantaneous netting or interval netting. The ECR is calculated by looking at the costs the Company avoids from exported energy. These costs are broken into five parts:

- Avoided Energy Costs
- Avoided Capacity or Generation Costs
- Avoided Fuel Risk Costs
- Avoided Transmission and Distribution Costs
- Avoided Line Losses

Once all the costs from the parts listed above are combined, they are adjusted to account for the costs incurred by integrating the generation into the system. A summary of these costs by component is provided in table 4.1 below, and descriptions of each component are provided in the following sections. Note that these values have not been adjusted to reflect the reduced value of non-firm deliveries, as discussed in Section 4.3.2.

Table 4.1: Summary of Export Credit Costs

¢/kWh Year	IRP Energy Value (Forecast)	*EIM Energy Value (Actual)*	Risk Value	LOLP Gen Capacity	LOLP Trans Capacity	LOLP Dist Capacity	Line Losses	Integr-ation Cost	Total Export Credit
2021	4.08	*2.83*	0.00	0.00	0.06	0.16	0.30	-0.02	4.57
2022	3.38	*4.35*	0.71	0.00	0.06	0.16	0.30	-0.02	4.58
2023	3.25		0.51	0.00	0.06	0.16	0.28	-0.61	3.66
2024	1.99		0.08	0.00	0.06	0.17	0.16	-0.19	2.27
2025	2.03		0.03	0.00	0.05	0.15	0.16	-0.12	2.30
2026	2.01		0.02	0.66	0.05	0.12	0.21	-0.09	2.97
2027	2.12		0.02	0.54	0.04	0.10	0.20	-0.24	2.79
2028	2.34		0.03	0.42	0.03	0.08	0.21	-0.23	2.87
2029	2.84		0.02	0.42	0.03	0.08	0.24	-0.04	3.59
2030	2.99		0.02	0.42	0.03	0.08	0.25	-0.05	3.74
2031	3.07		0.02	0.31	0.02	0.06	0.25	-0.02	3.70
2032	3.16		0.02	0.19	0.01	0.04	0.24	-0.03	3.64
2033	3.18		0.02	0.19	0.01	0.04	0.24	-0.01	3.68
2034	3.34		0.02	0.19	0.01	0.04	0.26	-0.01	3.85
2035	3.47		0.02	0.20	0.02	0.04	0.27	-0.01	4.00
2036	3.80		0.02	0.20	0.02	0.04	0.29	-0.01	4.35
2037	4.43		0.03	0.18	0.01	0.04	0.33	-0.005	5.01
2038	5.22		0.10	0.15	0.01	0.03	0.39	-0.005	5.90
2039	5.68		0.09	0.12	0.01	0.03	0.42	-0.005	6.34
2040	5.53		0.11	0.10	0.01	0.02	0.41	-0.03	6.14

4.1 Modeled Data as an Estimate for Actual Customer Export Data

In relation to using modeled data as an estimate for actual customer data, the Study Scope asked for a date when a full year of hourly AMI export data will be available.

Study Scope Item 4

Confirm when a full year of hourly AMI export data will be available for customer-generators.

As of April 27, 2023, deployment of AMI meters in Idaho is 97 percent complete. A full year of hourly AMI export data for Idaho customers for nearly all customer-generators will be available one year from this date.

4.2 Model Validation Method

The Study Scope required the Company to explain its method for verifying and validating the accuracy of its model and modeled customer data.

Study Scope Item 5

Explain the Company's method for verifying and validating the accuracy of its model and modeled customer export data.

As detailed in the discussion of the netting period, the estimate of hour-by-hour exported energy quantities were calculated using the data from all customer-generators taking service on Schedule 136 in northern Utah that are in the same climate zone as the Company's Idaho service territory.

While the Company maintains a sample of hourly information for Idaho customer-generators, the information taken from Utah customers in northern Utah is more suited for this Study for several reasons. First, the Idaho customer generation sample was put in place in 2014 and taken from a group of very different customers than what we see today. Roughly one-half of the generation systems in the 2014 Idaho sample were wind; however, most customer-generator systems are now operating solar PV. Second, the Idaho customer generation load research sample includes 44 sites and may not be a good sample. A sample this size produces estimates with sampling errors of 10 to 20 percent. Estimates taken from all northern Utah customer generators do not have the same sampling error. Finally, the Company's northern Utah and Idaho service territories have similar climates and geographic characteristics. The Company used the International Energy Conservation Code (IECC) climate zone map to identify Utah customers in climates similar to that of the Company's Idaho service territory.[4] Nearly all Idaho customers are in climate zone 6B. The Company identified Utah customers taking service on Schedule 136 also in climate zone 6B and calculated average hour-by-hour export quantities from these customers ("Northern Utah Customers").

To validate the accuracy of hourly export information taken from all of the Company's Northern Utah customer generators, the Company first reviewed sources of statistical error and bias. Sampling and measurement error are two major sources of statistical error. By definition, estimates taken from all customers are not subject to sampling error. Measurement errors are small—the Company purchases meters with accuracy certified by the manufacturer to be in compliance with the American National Standard Code for Electricity Metering (ANSI C12.1).

The Company also examined sources of bias. Estimates are biased if the group of customers being studied (in this case Idaho customer generators) is systematically different from the sample group (in this case customer generators in Northern Utah) used to represent that group

[4] See the 2021 International Energy Conservation Code (IECC) "Section C301 Climate Zones" for a map and a list of climate zones for each county. Counties in the Company's Idaho service territory are in climate zone 6B (cold and dry). https://codes.iccsafe.org/content/IECC2021P1/chapter-3-ce-general-requirements#IECC2021P1_CE_Ch03_SecC301

being studied. Possible systematic differences and sources of bias between these two groups include:

Differences in solar photovoltaic system sizes: If customer demand were otherwise equal, a larger solar photovoltaic system size would result in a greater portion of the total generation of the system being exported to the grid, and smaller portion used onsite.

Differences in actual monthly exports and deliveries: Building size and the types of load the customer has can contribute to differences in total customer demand, which could cause a difference in actual monthly exports and deliveries. Higher total usage, with the same generation, would result in lower exports.

Different amounts of solar irradiance (how intense the sunshine is) and PV generation in the two regions: Idaho customer-generators are concentrated primarily in counties surrounding Idaho Falls. This is 150 miles north of Logan, Utah, where most of the Northern Utah Customers are concentrated. Geographic differences could produce different levels of solar irradiance and PV generation.

The Company first compared the installed capacity of customer generation systems of Northern Utah Customers and Idaho to determine if there was a systematic difference in system sizes. The Company found a small difference in system sizes—the installed capacity of Idaho customers' systems is 5.2 percent lower than the capacities of Northern Utah Customers. Table 4.2 presents the mean installed capacity for each of these groups.

Table 4.2: Northern Utah Customers and Idaho System Size (Installed Capacity)[5]

Population	Installed Capacity (kW)
Average Northern Utah Customers	9.0
Average Idaho	8.5
Percent Difference	***-5.2%***

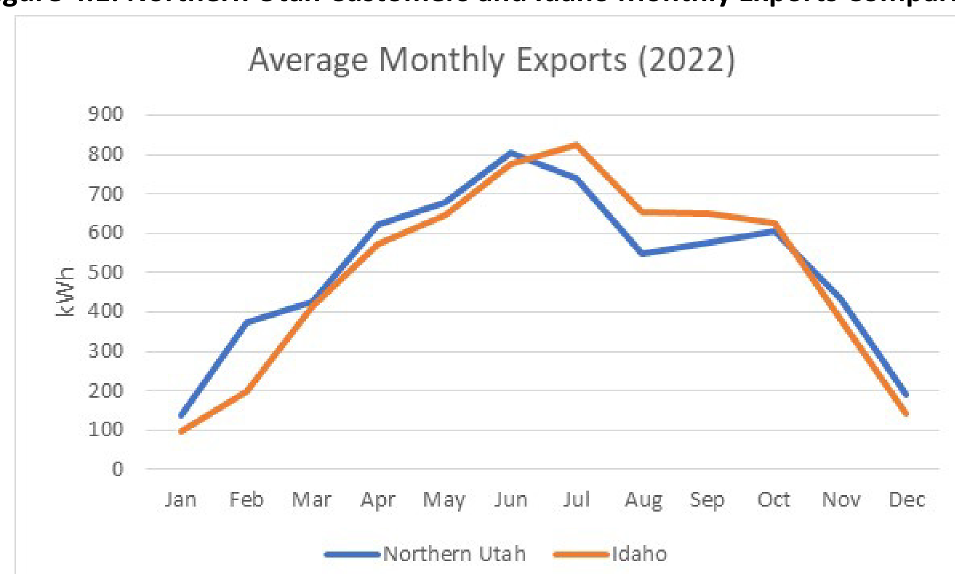
Next, the Company compared actual average monthly deliveries and exports from Idaho customer-generators against Northern Utah Customers in 2022. The distribution of exports across months for Idaho and Northern Utah Customers is similar as shown in Table 4.3 and Figure 4.1.[6]

[5] Supporting data provided in Appendix 4.4: Idaho Export Profile Validation Avg Capacity
[6] Supporting data for Table 4.3 and Figure 4.1 provided in Appendix 4.5: ID Export Profile Validation Monthly Exports

Table 4.3: Northern Utah Customers and Idaho Average 2022 Monthly Exports

Month	Average Exports (kWh)		12-Month Shape	
	Northern Utah	Idaho	Northern Utah	Idaho
Jan	139	95	2%	2%
Feb	375	199	6%	3%
Mar	426	412	7%	7%
Apr	621	572	10%	10%
May	677	644	11%	11%
Jun	804	776	13%	13%
Jul	741	824	12%	14%
Aug	549	655	9%	11%
Sep	575	651	9%	11%
Oct	607	625	10%	10%
Nov	434	383	7%	6%
Dec	189	143	3%	2%
Total	**6,136**	**5,980**	**100%**	**100%**

Figure 4.1. Northern Utah Customers and Idaho Monthly Exports Comparison



The Company found that Idaho customers exported slightly less than Utah customers in winter and shoulder (Fall and Spring) months, while exporting more in summer months. The weighted average absolute difference in monthly exports between Idaho and Northern Utah Customers is about 11 percent (weighted by monthly exports).

Finally, the Company used estimated solar PV generation information to compare the hourly shape of systems in Idaho against those customers located in Utah climate zone 6B. This involved first determining the areas where there are customer-generators in Utah climate zone

6B and in Idaho. Sixty-nine percent of all the customer generation capacity in Idaho is concentrated in the counties surrounding Idaho Falls including Bonneville (37 percent), Jefferson (20 percent), and Madison (12 percent) counties. In Utah climate zone 6B, counties near Logan; Cache (33 percent), Summit (28 percent), and Box Elder (20 percent), are about 82 percent of the installed capacity.

The Company used the National Renewable Energy Laboratory's PVWatts[7] calculator to estimate the hourly solar PV generation for a typical system located in Idaho Falls, ID and Logan, UT. PVWatts is a publicly available online calculator that estimates the amount of electricity generated by a typical solar PV system..

For each location, the Company estimated the hourly output of an 8 kW solar PV system. The Company then calculated each location's solar PV generation by month. The Company then summarized this information into averages for 12-month by 24-hours and calculated the Weighted Mean Absolute Percentage Error ("wMAPE"), a statistical test, between the Idaho and Utah production profiles for each time interval. To understand the total difference across months and the hourly difference within months, two versions of wMAPES were calculated:

> **Monthly Weighted Mean Absolute Error**: This statistic captures differences in the total Utah and Idaho values across months. If one location produces more than another in a specific month, this wMAPE will be higher for that month.
>
> **Hourly Weighted Mean Absolute Error:** This statistic measures the difference between Idaho and Utah hourly production profiles within months. It compares the average 24-hour shape for each month, ignoring differences in production across months. If solar PV systems in one location produce more later in the day than the other, these wMAPEs will be higher.

Table 4.4 shows the wMAPES for each month from the monthly and hourly perspectives. Months with higher monthly wMAPEs have a larger difference in both total solar PV generation for the month *and* across hours within the month. Months with higher hourly wMAPEs exhibit differences in 24-hour shapes (ignoring differences across months).

Winter months exhibit the greatest errors, which reflect both differences in location and the number of sunny days. This finding is similar to the prior comparison of monthly exports. Overall, the wMAPEs are 7.9% across the year and 5.4% within months.

[7] See https://pvwatts.nrel.gov/

Table 4.4: Solar Production Difference - Weighted Mean Absolute Percentage Errors[8]

Month	Monthly Mean Absolute Percentage error	Hourly Mean Absolute Percentage Error
January	18.7%	14.0%
February	8.7%	9.5%
March	4.6%	4.7%
April	7.7%	3.9%
May	8.3%	7.4%
June	7.5%	3.5%
July	5.0%	2.4%
August	5.7%	4.7%
September	5.2%	3.9%
October	5.3%	3.9%
November	14.8%	8.3%
December	26.5%	13.8%
Weighted Annual Average	**7.9%**	**5.4%**

The Company concludes from this analysis:

- System sizes for Idaho customer-generators are like those of Northern Utah Customers. The Company found that the Idaho systems have installed capacities that are approximately 5 percent lower than northern Utah systems.
- Winter months show a larger difference in total solar PV generation (greater than 10 percent wMAPE).
- Within months and across hours, the difference between the Logan, Utah and Idaho Falls, Idaho generation shapes is small—mostly less than 10 percent, on average.

The Company expects that differences in hourly export shapes between Northern Utah Customers and Idaho will be like the differences found in the Logan and Idaho Falls generation shapes. While the Company expects a greater difference in exports in the winter months and a smaller difference in the summer months, its analysis indicates that the overall difference will be small.

4.3 Avoided Energy Value

The Study Scope requested the avoided energy value be calculated using the energy price assumptions in the Company's most recently acknowledged IRP.

[8] Supporting data provided in Appendix 4.6: ID Export Profile Validation PV Watts Production

Study Scope Item 6

Calculate the avoided cost of exported energy using the energy price assumptions in the Company's most recently acknowledged Integrated Resource Plan ("IRP").

The Commission acknowledged the Company's 2021 IRP in August 2022. The 2021 IRP included a variety of price and policy scenarios, with the main scenario including a medium gas price forecast and medium greenhouse gas costs. These assumptions are a part of the hourly market price forecasts, based on input assumptions used in the Company's September 2020 official forward price curve. Within the IRP models, energy value varies by location because of limits in transmission and the balance of supply and demand. As a result, energy value in the Company's Idaho service territory will vary from the price at distant market points. With that in mind, for the purpose of calculating the energy value and cost-effectiveness of energy efficiency measures, the Company uses hourly marginal resource costs reported by its IRP models.

The Company notes that energy price assumptions in the 2021 IRP will be three years out of date in September 2023.

The Company also notes that the forecast wholesale prices used in the IRP may not be the best way to actually capture the value of customer generation exports. Specifically, customer generation exports will tend to be lower when customer load is high because a greater portion of the customer's generation can be devoted to the customer's own usage needs under those conditions. If, for example, the customer's load is high because of effects that impact the system as a whole, such as regional weather conditions like a heat wave, this would cause lower exports when demand and energy costs are highest. This situation where exports are lower during times of peak load times is not captured in the forecast modeled using 2021 IRP results, but it is present in after the fact historical data. An alternative to using IRP information that captures this situation is using actual Energy Imbalance Market ("EIM") prices to value customer generation exports by each hourly period. Because EIM prices are public, do not require complicated forecasts or models, and more accurately capture the real conditions of a historical time period, they can be a good option for calculating energy value. Energy values based on 2021 IRP results and historical EIM prices are presented in Table 4.1.

4.3.1 Supporting Documentation for Avoided Energy Value

The Study Scope requested the supporting documentation for the Company's avoided energy value calculation.

Study Scope Item 6(a)

Provide supporting documentation.

The 2021 IRP energy values shown in Table 4.1: Summary of Export Credit Costs shows the value of customer exports using the hourly incremental energy prices for the Goshen, Idaho location from the Company's 2021 IRP preferred portfolio results, which were also used for the Idaho energy efficiency cost-effectiveness evaluation. The EIM energy values shown in Table 4.1 reflect the value of customer exports using average hourly historical EIM prices in the Real-Time Pre-Dispatch market (15-minute market) for the PacifiCorp East Load Aggregation Point location (a weighted average for load points in PacifiCorp's East Balancing Authority Area).

4.3.2 Supporting Documentation for Non-Firm Energy

The Study Scope requested the Company provide calculations and documentation showing why the avoided cost of exported energy produced by customer-generators should be valued at 85% of the total avoided energy value.

Study Scope Item 7

Provide the calculations and documentation showing why the avoided cost of exported energy produced by customer-generators should only be valued at 85% of the total avoided energy value.

Customer-generators are non-firm energy, meaning that there is no guarantee that exported energy will be delivered to the grid at specific times. Commission practices for pricing qualifying facilities ("QF") value non-firm energy deliveries at 85% of the total avoided energy value. Because customer-generators make no commitment to export particular quantities of energy to the grid, they are considered non-firm energy. An 85% adjustment is similar to current practices for both the surrogate avoided resource ("SAR") methodology when pricing qualifying facilities and for the customer generation net billing credit for PacifiCorp customers taking service on Schedule 135.[9]

However, the SAR Methodology does have some limitations since it does not have hourly detail. Using EIM prices for the avoided energy value may be preferrable since it can better value customer exports in particular hours. Because EIM prices are set shortly before the time of delivery, they do not have the same risk as firm delivery commitments made in advance and may not require as large of a non-firm adjustment. EIM prices are also public, which allows for greater transparency, and they can better reflect the value of export timing than a forecast.

Idaho Regulatory History of SAR Methodology and Non-Firm Energy Pricing

The Commission has approved the SAR Methodology for determining avoided costs for standard qualifying facility resources up to at least 100 kW in nameplate capacity. Under the

[9] In addition to the 85 percent adjustment made for non-firm energy under the SAR Methodology, Schedule 135's Net Metering Rate Credit for non-residential customers is calculated at 85 percent of the monthly weighted average of the daily on-peak and off-peak Mid-Columbia Intercontinental Exchange Electricity Price Index (Mid-C ICE Index) prices for non-firm energy.

SAR Methodology, avoided energy costs reflect forecast prices for natural gas and the assumed heat rate of a combined cycle combustion turbine. [10]

In Order No. 29632, the Commission found that energy "delivered outside of the 90/110 performance band (i.e., non-conforming energy) would be priced at 85 percent of the *non-firm* market price or the contract price, whichever is less."[11] The non-firm market price has been found by the Commission to equal to the 82.4 percent of the firm market price.[12] Based on the this, the formula for non-firm energy delivered outside the performance band for qualifying facilities is below:

*Non-firm market price outside of performance band = 85% * non-firm market price; where*

*Non-firm market price = 82.4% * firm market price*

Firm Energy and Non-Firm Energy

To better understand how the customer-generators differ from firm wholesale energy purchases or sales, it is helpful to understand some key aspects of firm wholesale energy transactions. At present, most firm wholesale energy transactions reflect a limited set of market products such as:

- Blocks of hours at a constant amount, typically Heavy Load Hours (HLH), Light Load Hours (LLH), or all hours.[13]
- Monthly products (covering every day in a month) are available prior to the start of a month, while transactions for individual days are only available a day or two before delivery.
- Typically traded in in blocks of 25 MW.
- Only a few locations have many buyers and sellers, such as Mid-Columbia or Palo Verde. There is a small number of buyers and sellers at most locations, and those buyers and sellers may not be interested in buying or selling a specific product.
- Such market products are considered firm because the seller is subject to costs for damages if it fails to provide deliveries as agreed.

Exports from customer-generators are very different from wholesale energy products. Customer-generators exports:

[10] *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource and Integrated Resource Planning Methodologies for Calculating Avoided Cost Rates*, Case No. GNR-E-Il-03, Order No. 32697 at 7-8 (Dec. 18, 2012).
[11] *In the Matter of Rocky Mountain Power's Application for Approval of Power Purchase Agreement between PacifiCorp and Birch Hydro Company*, Case No. PAC-E-20-07, Order No. 34889 at 2 (Jan. 14, 2021).
[12] *In the Matter of Rocky Mountain Power's Application for Approval of Power Purchase Agreement between PacifiCorp and Birch Hydro Company*, Case No. PAC-E-20-07, Order No. 34889 at 2 (Jan. 14, 2021).
[13] HLH is 6:00 a.m. to 10:00 p.m. (Pacific Prevailing Time) Monday through Saturday, excluding certain holidays. LLH is all other hours, namely 10:00 p.m. to 6:00 a.m. nightly, and all day on Sundays and holidays.

- Vary from moment to moment.
- Are not committed in advance.
- Are not delivered to major energy market locations.
- Provide no commitment to deliver. A customer may not have excess power to sell back to the utility, either because its generation is low or because its own energy usage is high.

A utility must provide energy equal to its customer load at all times. Both its supply of energy and loads are uncertain, as wind and solar generation output varies, load varies, and other sources of generation experience unplanned outages. Under nearly all conditions, a utility must have sufficient energy supply to balance its loads with enough extra energy to meet its reliability obligations.

Since the amount of exported energy sent to the grid may be different than expected, a utility must adequate energy supply to serve load. Such energy supply cannot support firm wholesale energy market sales if the amount of exported energy is less than expected, because such sales would need to be finalized at least a day in advance, if not longer. In addition, if the utility's energy supplies are only available for a few hours, they may not be able to support the entire duration and quantity of a market product (such as during the heavy load hour block of time or all day as discussed above in this report).

The difference in value between a firm market transaction and non-firm energy varies based on a variety of factors, including the hourly timing of non-firm energy, the supply and demand expectations of wholesale energy market buyers and seller, and the uncertainty in supply and demand, along with the next best alternatives for wholesale energy market buyers and sellers.

With the advent of EIM, significantly more market data is available that better matches up with the timing of exported energy. EIM prices reflect:

- Shorter periods of time (five or fifteen minutes).
- Energy delivery begins a few minutes after a dispatch instruction is received.
- No minimum quantity.
- Location-specific values for large scale energy resources, or values specific to PacifiCorp loads.

While no single wholesale energy market price can reflect the intertwined month-ahead, day-ahead, hour-ahead, and intra-hour planning and operations used to balance PacifiCorp's load and energy supply, EIM prices can be a better estimate of the actual value of customer exports.

4.4 Avoided Capacity Value

The Study Scope requested the Company analyze the capacity value of exported energy provided by customer-generators using either the LOLP study or by evaluating the amount of power exported to the grid by customer-generators during the top 100 peaking events in the last 10 years.

Study Scope Item 8

8. Analyze the capacity value of exported energy provided by customer-generators on a class basis using one of two methods: *a. Loss of Load Probability Study, or* *b. Determine the power that is reliably exported to the grid by net metering during peaking events. Use the top 100 peaking events from each of the past 10 years (1,000 peaking events). Use a reliability threshold of 99.5%. If, for example, the study determines that customer-generators provide no less than 1.5 MW of power during 99.5% of the peaking events, then use 1.5 MW as the basis for determining the capacity avoided by the customer-generator class.*

The Company has examined the capacity value of exported energy using the loss of load probability (LOLP) study from its IRP. The Company also looked at the top 100 peaking events from the past two years.

4.4.1 Loss of Load Probability Study

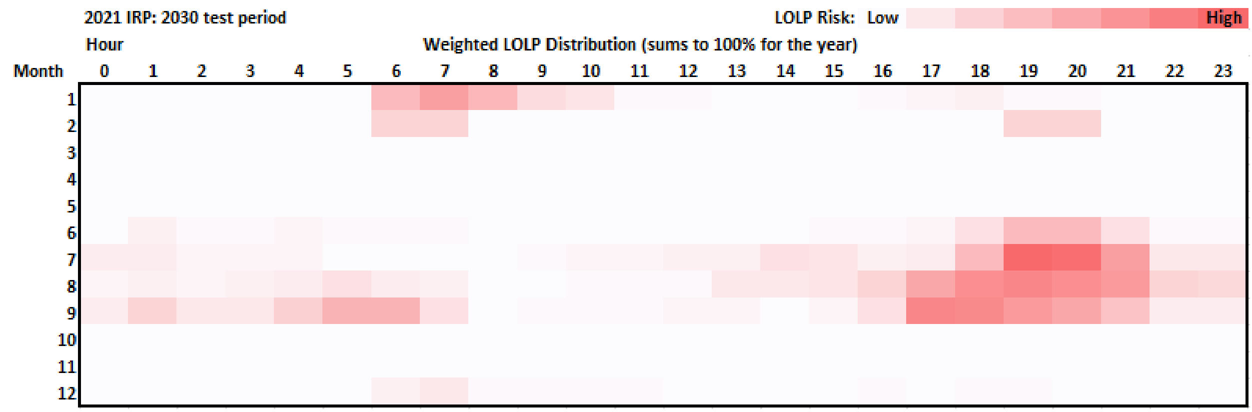
The Company's LOLP study from its 2021 IRP, is used to estimate the amount of capacity that customer generation exports provide. The study is discussed in the 2021 IRP in Volume II, Appendix K: Capacity Contribution[14].

The capacity factor approximation methodology described as the "CF Method" in Appendix K of the 2021 IRP can be used to estimate the amount of capacity a particular hourly amount of energy can provide from the LOLP results. The CF Method calculates the amount of capacity provided based on the expected availability of energy during times when the risk of loss of load is highest (the LOLP in each hour).

The Company calculated the amount of capacity provided from exported energy in the last two years (2021-2022) by month and hour (a "12x24 profile"), i.e. assuming that customer exports were neither higher, nor lower, than average during hours with LOLP. Figure 4.2 below shows the hours with higher LOLP shaded in red:

[14] Included with this Study as Appendix 4.7: Appendix K - Capacity Contribution - 2021 IRP

Figure 4.2: Weighted LOLP Distribution



As shown on Appendix 4.2: Export Credit Calculation, this results in the amount of capacity being provided from exported energy equal to 3.0% of their nameplate capacity, prior to accounting for avoided line losses. By comparison, the 2021 IRP identified that this value is 13% for large scale solar energy generation in Idaho. One of the key differences is that customer generation exports are sent to then grid after a customer uses the generation at its site. Large scale solar generation is also different, because it uses tracking technology where the panels are tilted to follow the sun throughout the day, which increases its generation in the morning and evening when LOLP is higher.

The LOLP distribution shown in Figure 4.2 reflects the timing of risks associated with the 2021 IRP preferred portfolio in calendar year 2030. These risks will evolve as the underlying portfolio changes, for example, risks during the day tend to diminish as more solar resources are added. Similarly, the risks during the day may increase if a portfolio is more reliant upon short-duration resources, like energy storage or demand response. The capacity contribution from exported energy is expected to drop from 6.8% in 2024, to 3.0% in 2030, and to 1.3% by 2036 as a result of the changing composition of the 2021 IRP preferred portfolio through time. This projection of capacity value through time has been incorporated in Table 4.1.

4.4.2 Historical Peak Conditions

The Company has compared historic customer generation exports and the top 10 percent load times over the past two years, spanning 2021-2022. During all hours in the top 10 percent of annual Idaho load, exports provided an average of 12.7% of its maximum generation, while during all hours in the top 10 percent of annual PacifiCorp system load, exports provided an of 14.4% of its maximum generation. Many of the top hours have significantly lower exports, as shown in Table 4.5 below. Much less than 1% of maximum generation is available for more than 99.5% of top hours.[15]

[15] Data for analysis provided in Appendix 4.1: Export Profile Jan21-Dec22.

Table 4.5: Customer Generation Exports During Peak Loads

Top 10%	Exceedance During Peak Load Hours, % Nameplate (by Percentile)							
Load	50%	60%	70%	80%	90%	95%	99.5%	100%
Idaho	4.73%	0.58%	0.0387%	0.0097%	0.0020%	0.0013%	0.0005%	0.0002%
System	9.98%	4.29%	0.9985%	0.0460%	0.0110%	0.0042%	0.0012%	0.0005%

These results only look at top load hours and do not account for reliability and risk that is related to energy supply. The 2021 IRP results account for periods when loads are high and energy supply availability is low. Energy supply availability is particularly important as solar generation is becoming a greater share of PacifiCorp's energy supply. As a result, the added reliability benefits from customer generator exports (which are primarily solar) are reduced.

4.4.3 Time-Differentiated Capacity Values

The Study Scope requested the Company provide hourly time-differentiated capacity values.

Study Scope Item 9

Provide hourly time-differentiated capacity values.

PacifiCorp has calculated hourly generation, transmission, and distribution capacity values (in $/MWh) based on the 2021 IRP LOLP capacity analysis described above. Hourly capacity values were assigned by the LOLP by month and time of day shown in Figure 4.2. Beginning in June 2025, the on-peak period for the residential time of day option Schedule 36 will be all days from 3 p.m. to 11 p.m. during the months of June through October and 6 a.m.to 9 a.m. and again from 6 p.m. to 11 p.m. during the months from November through May. In a future net billing program, the capacity value of the export credit could be given a higher value during these on-peak hours and a lower value during off-peak hours. Table 4.6 below shows the year-by-year capacity values that are shown on Table 4.1 but broken out by on-peak and off-peak time periods and by season. Note that each of the four time of use period definitions shown result in the same compensation for a customer whose exports align with the average export profile. Customers who are able to export more during on-peak and/or summer periods would receive higher compensation with differentiated rates.

Table 4.6: Capacity Value by Time of Use Period

	1. Annual	2. Time of Use		3. Seasonal		4. Seasonal & Time of Use			
¢/kWh Year	Annual All Hours	Annual On-Peak	Annual Off-Peak	Summer All Hours	Winter All Hours	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
2021	0.21	1.32	0.06	0.47	0.03	1.57	0.12	0.07	0.02
2022	0.22	1.35	0.06	0.48	0.03	1.60	0.12	0.07	0.02
2023	0.22	1.38	0.06	0.49	0.03	1.63	0.12	0.07	0.03
2024	0.23	1.41	0.06	0.50	0.03	1.67	0.12	0.07	0.03
2025	0.20	1.21	0.06	0.44	0.02	1.44	0.12	0.06	0.02
2026	0.83	4.87	0.26	1.83	0.09	5.78	0.56	0.26	0.09
2027	0.68	3.83	0.24	1.51	0.07	4.54	0.54	0.21	0.06
2028	0.53	2.75	0.21	1.18	0.05	3.26	0.51	0.17	0.04
2029	0.53	2.34	0.27	1.11	0.10	2.73	0.59	0.33	0.09
2030	0.53	1.91	0.34	1.03	0.16	2.18	0.67	0.51	0.15
2031	0.39	1.52	0.23	0.80	0.09	1.76	0.49	0.29	0.08
2032	0.24	1.12	0.12	0.55	0.01	1.33	0.30	0.06	0.01
2033	0.25	1.06	0.13	0.55	0.02	1.25	0.32	0.10	0.02
2034	0.25	1.00	0.14	0.54	0.03	1.17	0.34	0.14	0.03
2035	0.25	0.93	0.16	0.53	0.05	1.08	0.36	0.17	0.04
2036	0.26	0.86	0.17	0.52	0.06	0.99	0.38	0.21	0.05
2037	0.23	0.90	0.13	0.40	0.10	0.75	0.29	1.68	0.04
2038	0.19	0.95	0.09	0.27	0.14	0.51	0.19	3.19	0.03
2039	0.16	0.99	0.04	0.14	0.18	0.26	0.10	4.73	0.01
2040	0.13	1.04	0.00	0.00	0.22	0.00	0.00	6.31	0.00

4.5 Avoided Risk

The Study Scope requested the Company evaluate avoided risk by examining whether there is a fuel price guarantee value provided by on-site generators as a class.

Study Scope Item 10

Analyze whether there is a fuel price guarantee value provided by on-site generators as a class.

PacifiCorp's 2021 IRP included statistical analysis, which examined costs considering variations in load, hydro generation output, electricity and natural gas prices, and unexpected outages of thermal generators. PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures used these results to identify the additional value associated with these risks. PacifiCorp has calculated the avoided risk value for customer exports using the same risk values that were used for energy efficiency. Over the time period for the 2021 IRP, the risk value increases the energy value for customer exports by 3.9%, or $1.24/MWh as shown on summary tab of Appendix 4.2: Export Credit Calculation.

5.0 Project Eligibility Cap

An evaluation of the pros and cons of setting a customer's project eligibility cap at different predetermined caps and demand levels was requested by the Study Scope.

Study Scope Item 11

Analyze the pros and cons of setting a customer's project eligibility cap according to a customer's demand as opposed to predetermined caps of 25 kW and 100 kW. a. Analyze at 100% of demand. b. Analyze at 125% of demand.

Per the estimated load information used in the Company's last general rate case[16], the estimated maximum peak is 8.4 kW for the typical residential customer taking service on Schedule 1 and 11.5 kW for the typical residential customer taking service on Schedule 36. At 25 kW, the current cap is well above 125 percent of the typical customer's demand. Setting a capacity level that is based upon an individual customer's demand could be administratively burdensome and could create frustration for smaller customers who want to install a larger facility. It could also encourage customers to have a higher peak load before they request to interconnect an onsite generation system. The complications of setting a capacity level based on the individual customer's demand would be the same at 100% of demand and at 125% of demand. For residential customers, the benefits of a generic 25 kW cap is that it is administratively simple, easy for customers to understand, does not encourage a customer to increase its demand, and is set at a level that is well above the maximum demand for the typical customer. The downside of a generic cap is that it might be too large for smaller energy users causing them to unnecessarily oversize their system and conversely might be too small for very large users and not provide enough capacity to meet their energy needs.

For non-residential customers, the pros and cons of a generic 100 kW cap are the same as for residential customers for smaller users. For larger users, a 100 kW cap may be significantly less than the level that would be needed to meet their annual energy needs. However, a larger user can become a qualifying facility and be compensated for their generation output at an avoided cost rate. Avoided cost pricing for qualifying facilities is more accurate since it is set for specific technologies (i.e. wind, fixed tilt solar, tracking solar, and baseload) and takes into

[16] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations.* Docket No. PAC-E-21-07

consideration whether the customer wants to provide on a firm[17] or non-firm basis. A downside of becoming a qualifying facility can be that it is a more onerous process for a customer to interconnect. Table 5.1 below shows the pros and cons of using a generic cap versus using a multiple of the customer's actual demand to set an individualized cap:

Table 5.1: Pros and Cons of a Generic Cap (25 kW for Residential and 100 kW for Non-Residential)

Residential 25 kW Cap	Pros	Cons
	Administratively Simple	Too Large for Smaller Users which Might Cause Them to Invest in too Large of a System
	Easy to Understand	Too Small for Very Large Users which Could Limit the Ability to Meet Energy Needs
	Does Not Encourage Bigger Peak Demand	
	Level is Sufficient for Most Customers	
Non-Residential 100 kW Cap	**Pros**	**Cons**
	Administratively Simple	Too Large for Smaller Users which Might Cause Them to Invest in too Large of a System
	Easy to Understand	Too Small for Very Large Users which Could Limit the Ability to Meet Energy Needs
	Does Not Encourage Bigger Peak Demand	Greater than 100 kW Systems Must Become a Qualifying Facility which Has a More Challenging Interconnection Process
	Greater than 100 kW Systems Must Become a Qualifying Facility which Has More Accurate Pricing	

6.0 Avoided Transmission and Distribution Costs

The Study Scope requested the Company to calculate the value of transmission and distribution costs that could be avoided by customer-generator exports to the grid.

[17] If a qualifying facility elects firm pricing, they receive a higher rate, but are also subject to liquidated damages for non-performance.

Study Scope Item 12

Quantify the value of transmission and distribution costs that could be avoided by energy exported to the grid by net metering customers using the methodology for calculating the avoided transmission and distribution costs provided by energy efficiency programs.

PacifiCorp's estimation of the value of energy efficiency measures includes an assumption that local transmission and distribution upgrades could be pushed into the future.

When the Company provides electric service to a new subdivision it utilizes standard system designs based on the number and size of expected homes in the new subdivision. It does not assume any level of customer generation because doing so would risk under-sizing the equipment.

In the absence of specific information about transmission and distribution capacity needs and their timing with expected customer exports, PacifiCorp has estimated the potential avoided transmission and distribution costs using the system LOLP-based capacity value of 3.0%, as previously discussed. Using the same avoided transmission and distribution upgrade costs applied in PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures based on the 2021 IRP results in a value of $1.10/MWh over the 2021 IRP time period.

7.0 Avoided Line Losses

The Study Scope requested the Company the avoided line loss calculations at a level that an average customer could understand.

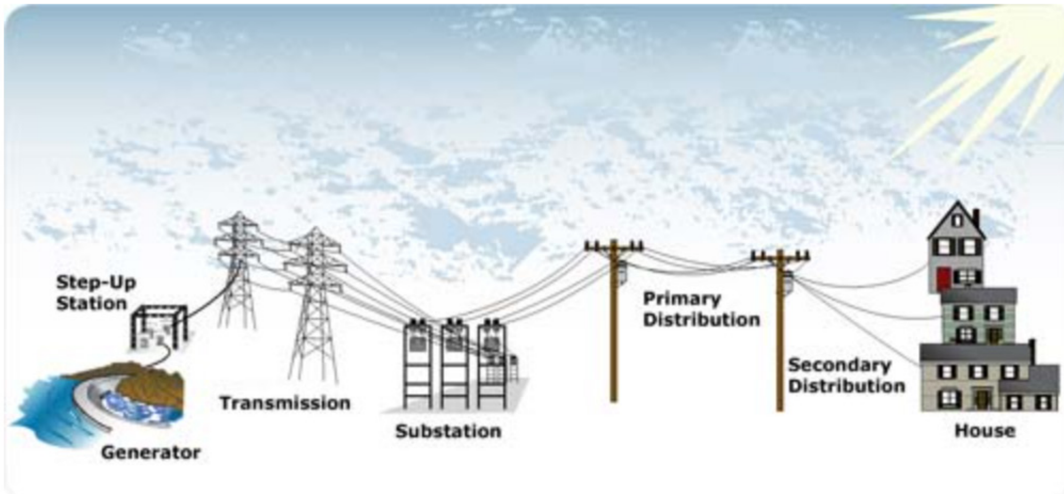
Study Scope Item 13

Explain the avoided line loss calculations at a level that an average customer can understand.

As electricity travels from a generator to a customer, some of the energy is lost. This is a phenomenon known as line losses. One benefit of customer generation is that it is located closer to the customer and therefore travels a shorter distance which results in lower line losses.

Line losses are calculated as the difference between the total energy generation that is put into the grid and the total energy metered at customer sites. The line losses are separated into three categories: transmission, primary and secondary. Transmission line losses account for those line losses that occur over the transmission system. Primary line losses include those losses that occur on distribution voltages in the range from 2.2kV to 34.5 kV with most circuits at 12.4 kV. Secondary line losses include those losses that occur on distribution systems that are low voltage in the 120V to 480V range.

Figure 7.1: Transmission, Primary, and Secondary Components of an Electrical System[18]



The line losses incorporated in the Company's current rates are from its 2018 Line Loss Study. See Appendix 7.1 for the 2018 Line Loss Study. That study identified "Demand" loss factors, based on losses during peak load conditions, as well as "Energy" loss factors, based on average losses over the course of a year. The 2018 Line Loss Study identified line losses in Idaho specific to the following voltage level at which a customer connects to the grid:

Table 7.1: Idaho 2018 Demand and Energy Loss Summary

Voltage Class	Demand Loss Factor	Energy Loss Factor
Transmission	3.816%	3.503%
Primary	8.121%	7.082%
Secondary	9.834%	9.061%

For customer-generators, the Company expects to apply the export credit to generators interconnected at secondary voltage levels, and to meter the exports before they go onto the secondary distribution system. The energy exported from the customer-generators will then incur some line losses traveling upstream across the secondary distribution system to other customers, so it will not avoid the entire line losses associated with serving load on the secondary distribution system. Therefore, the Company recommends crediting exports for avoiding line losses on the transmission and primary distribution systems only. If customer exports and customer generation exceeded the load on a particular distribution circuit, electricity could potential be transferred back up to higher voltages and could incur higher losses. For distribution capacity, avoided line losses are measured relative to losses at the transmission demand level, as losses incurred on the transmission system would not have been transferred across the distribution system.

[18] Transmission Line FAQ, GATEWAY WEST Transmission Line Project, http://www.gatewaywestproject.com/faq_general_transmission.aspx (last visited Feb. 20, 2023).

8.0 Integration Costs

Integration costs refer to the additional cost of generators with variable output. Integration typically includes costs related to the uncertainty and variation in variable energy from moment to moment, and these system impacts have been estimated in the 2021 IRP as described in more detail below. For customer generation, integration costs could potentially include equipment and/or operational changes to manage impacts on the distribution system, particularly at high penetration levels, but the Company has not identified any specific costs associated with distribution system impacts from customer generators in Idaho.

The Study Scope requested the Company to calculate the dollar impact of delaying a study of the integration charges for net metering customer until AMI data is available.

Study Scope Item 14

Study other methods for determining the integration costs of net metering customers as a class. Calculate the dollar impact of deferring a study of the integration charges for net metering customers until AMI data is available, and if different, calculate the dollar value of using a zero placeholder until AMI data is available.

The 2021 IRP includes an analysis of wind and solar integration costs in its Flexible Reserve Study ("FRS") which is included in this Study as Appendix 8.1: Appendix F – Flexible Reserve Study- 2021 IRP. That analysis estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards as well as the incremental cost of this regulation reserve.

PacifiCorp does not have a real-time forecast of customer generation exports that could be used to identify specific integration requirements, but it is possible to measure changes within each hour compared to the hourly average. During 2021-2022, the historical customer export data had a mean average percent error ("MAPE") of 8.6 percent, when comparing 15-minute values to the hourly averages. By comparison, the large scale solar in the FRS had a lower MAPE of 7.2 percent. This indicates that large scale has a proportionately smaller contribution to regulation reserve requirements than customer exports.

Because the variation in customer generation exports exceeds that of large-scale generation, it is reasonable to expect integration costs for customer generation exports to be higher. In light of this, the use of the large-scale solar integration costs likely understates the actual cost but is reasonable. Using the latest large scale solar integration costs approved in Order No. 34966 in PAC-E-20-14, the solar integration costs for 2023 is currently $0.24/MWh[19]. Assuming an

[19] See Appendix 8.2: Wind and Solar Integration Charges Approved in Order No. 34966

average annual exports of 5,000 kWh per customer, the dollar impact of using a zero placeholder for integration costs until AMI data is available is $1.20 per customer per year.

9.0 Avoided Environmental Costs and Other Benefits

9.1 Grid Stability, Resiliency, and Cybersecurity

The Study Scope requested the Company to quantify the value of grid stability, resiliency, and cybersecurity provided by on-site generators.

Study Scope Item 15

Quantify the potential value of grid stability, resiliency, and cybersecurity protection provided by on-site generators as a class and different penetration levels.

The Federal Energy Regulatory Commission ("FERC") defines resilience as "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and /or rapidly recover from such an event". To achieve any resiliency or grid stability benefits as defined above, on-site generation must be combined with storage since on-site generators, on their own, are susceptible to and can even enhance disruptive events.

Without storage, on-site generation does not provide grid benefits because in the event of an outage, systems are designed to power down for safety at any penetration level of on-site generation. The Company has also found that on-site generation does not provide cybersecurity benefits and can create additional cybersecurity risk because on-site generation creates more potential access points to the grid.

9.1.1 Grid Benefits of On-Site Generation with Storage

The grid *can* benefit from on-site generation when it is combined with solar. Battery management programs, like Wattsmart Batteries, provide four primary grid service benefits: 1) frequency regulation services 2) peak load management 3) circuit congestion relief, and 4) backup power.

In 2019, the Company was part of a partnership that developed a 600-unit all-electric residential community in Utah, where each apartment was outfitted with batteries paired with rooftop solar. The project provides 12.6 MWh of storage that is dispatchable by RMP through the Distributed Battery Grid Management System. An evaluation of this project identified the four primary grid service benefits listed above.

Without battery storage, on-site customer generation does not provide either frequency regulation services, peak load management, circuit congestion relief or backup power.

9.1.2 Community Resiliency Benefits of Customer Generation with Storage

When a catastrophic disaster strikes, backup power paired with storage can ensure emergency services, such as fire, medical, and shelter services, continue to operate. On-site generation with storage provides value to the community from avoided property damage, injuries, fatalities, and lost productivity. While there is no standard method for determining the community resiliency value of customer generation some tools can help determine the value for individual sites.

An evaluation of Pacific Power's Community Resiliency Pilot used the Federal Emergency Management Agency's ("FEMA") benefit-cost analysis tool to determine the potential resiliency value for customer generation and batteries at specific sites that provide vital services—fire stations, data centers and designated shelters. FEMA's calculator determines the value of maintaining these services based on the type of emergency and the facility category. For example, analysis for a fire station considers the probability of property loss, the dollar value of the loss, and the number of fire incident prior to and during the outage. The tool also determines avoided injuries and deaths from maintaining fire service. The resiliency benefits can vary significantly from site-to-site depending on the unique characteristics of the facility, the community the facility serves, and the type of disaster.

None of the community resiliency benefits outlined above is possible without battery and storage combined together since battery storage provides the backup power required during a disaster. Also, the benefits outlined above are not relevant to the purposes of this Study, which is focused on the benefits of on-site generators connected to the grid, *as a whole,* and not any one site and the benefits it might give to a community in the event of a disaster. Further, those benefits are unquantifiable and do not accrue specifically to customers of the utility in their capacity as consumers of energy.

9.1.3 Customer Generation and Cybersecurity Protection

Cyber-attacks are potential resiliency events. Thus, the cybersecurity protection benefits of customer generation with storage are the same as those described above. In the event of a catastrophic cyberattack, customer generation and storage could provide sustained power to vital services.

However, increasing penetration of customer generation could increase cybersecurity risks. The U.S. DOE's report on "Cybersecurity Consideration for Distributed Energy Resources on the U.S. Electric Grid" identifies several cybersecurity risks from distributed energy resources.[20] When a

[20] *Cybersecurity Considerations for Distributed Energy Resources on the U.S. Electric Grid*, U.S. DOE Office of Cybersecurity, Energy Security, and Emergency Response and the Office of Energy Efficiency and Renewable Energy, October 2022. https://www.energy.gov/sites/default/files/2022-10/Cybersecurity%20Considerations%20for%20Distributed%20Energy%20Resources%20on%20the%20U.S.%20Electric%20Grid.pdf

customer-generator connects to the grid, it creates a new access point, which adds incremental risk for cyberattacks. Most customer generation systems use solid-state inverters to produce output and sync with the grid. These inverters are software-driven and digitally controlled. The improper application of this software—such as through a cyberattack—could affect reliability and grid stability.

9.2 Public Health and Safety

The Study Scope requested the Company to quantify the value to local public health and safety from reduced local impacts of global warming.

Study Scope Item 16

Quantify the value to local public health and safety from reduced local impacts of global warming such as reduced extreme temperatures, reduced snowpack variation, reduced wildfire risk, and other impacts that can have direct impacts on Rocky Mountain Power customers.

The value of customer generation exports with respect to global warming harm reduction is difficult to quantify. The greenhouse gas costs in the 2021 IRP represent possible federal policy that would impact the dispatch of emitting resources, and do not represent local impacts, which are much more complex. Some of the referenced global warming impacts, including impacts on retail load and hydropower production, directly impact PacifiCorp's loads and resources, and climate-related effects on these inputs have been incorporated in PacifiCorp's 2023 IRP.

Though it is imperfect for identifying local impacts, PacifiCorp's avoided energy value, addressed in section 4.3 of this Study, includes the impact of assumed medium greenhouse gas costs, consistent with assumptions from the 2021 IRP. Medium greenhouse gas costs are reflected in market prices, as well as in the dispatch cost of PacifiCorp's coal and natural gas-fired resources, but it is not possible to differentiate greenhouse gas costs from energy and other variable costs within the reported hourly energy value. PacifiCorp's 2021 IRP also included analysis using a social cost of greenhouse gases ("SCGHG"); however, this represents global public health and safety impacts, rather than local impacts.

Another possible value of customer generation exports is via Renewable Energy Certificates ("RECs"), which are addressed in section 9.4 of this Study below.

9.3 Economic Benefits

The Study Scope requested the Company to quantify the value to local economic benefits from on-site customer generation.

Study Scope Item 17

Quantify local economic benefits, including local job creation and increased economic activity in the immediate service territory.

Quantifying local economic benefits of increased economic activity is difficult, if not impossible, to quantify with a degree of certainty. In addition, the Company's generation, transmission, and distribution activities in its current service territories provide economic benefits. However, the Company does not charge customers for these benefits in electric rates. Allowing difficult-to-quantify economic benefits in the ECR would not be fair to non-participating customers.

9.4 Possible Net Value of Renewable Energy Credits

The Study Scope requested the Company to quantify the net value of RECs sales from on-site generation.

Study Scope Item 18

Quantify the possible net value of Renewable Energy Credit sales produced by net metering exported energy.

Currently, Idaho does not have a renewable portfolio standard ("RPS"), so the benefits of RECs would come from REC sales. Only renewable generation delivered to the electric grid can qualify for RECs, and there are administrative requirements to certify renewable resources and assign RECs to their production.

To create RECs, the renewable energy generator must be registered with the Western Electricity Coordinating Council ("WECC") and the Western Renewable Energy Generating Information System ("WREGIS"). Renewable energy cannot be monetized through REC sales without this process in the WECC region. Coordinating the certification and tracking of the RECs would be complex and could require a full-time employee to administer. The Company expects the administrative costs would exceed any revenues generated from REC sales.

At present, PacifiCorp does not sell all the RECs it generates on behalf of its Idaho retail customers, as the market for RECs is limited. To the extent that there were other parties interested in purchasing RECs from Idaho customer-generator exports, a $1/MWh REC price would equate to approximately $5 per year in incremental export credit value for an Idaho customer-generator, assuming 5,000 kWh of exports annually, which represents approximately half of their annual generation.

9.5 Reduced Risk from End-of-Life Disposal

The Study Scope requested the Company to quantify the reduced risk from end-of-life disposal concerns for the Company compared to fossil-fueled resources.

Study Scope Item 19

Quantify the reduced risk from end-of-life disposal concerns for the Company compared to fossil-fueled resources.

Investment in utility scale resources considers end-of-life closure costs to determine least cost resources. To the extent capacity benefits displace a new generation resource, this potential benefit is already captured in that category.

10.0 Recovering Export Credit Rates in the ECAM

10.1 Current Export Credit Recovery

To better understand how export credit rates may be recovered in the Energy Cost Adjustment Mechanism ("ECAM"), the Study Scope asked the Company to explain the method currently used to record net metering bill credit costs.

Study Scope Item 20

Explain the method currently used to record net metering bill credit costs.

Currently, bill credits for net metering are used to reduce the energy charges that are paid to the Company. These net metering bill credits therefore reduce the Company's retail revenue.

10.2 Recovery Allocation

The Study Scope asked the Company to quantify the current amount of net metering costs allocated to each class.

Study Scope Item 21

Quantify the current annual amount of the net metering costs allocated to each class.

Table 10.1 below shows the reduction in revenue for each class attributable to exported energy that is valued at retail energy charges:

Table 10.1: Net Metering Reduction in Revenue by Class

	Residential Sch 1	Residential Sch 36	General Service Sch 23	General Service Sch 6	Total
Exported Energy (MWh)	8,555	2,183	565	123	11,426
Value at Retail Rate	$916,330	$269,067	$51,091	$5,242	$1,241,731

The Study Scope required the Company to explain how these costs have been allocated and recovered between rate classes for the past five years.

Study Scope Item 22

Present and explain how these costs have been allocated and recovered between rate classes for the past five years.

In between rate cases, the Company absorbs the cost of reduced revenue from net metering. In 2021, the Company filed a rate case that updated class revenues and that took effect January 1, 2022. The rate case before the 2021 rate case occurred ten years before and took effect on January 10, 2012, with a second-year price change that took effect on January 1, 2013. During that timeframe, onsite generation adoption was still in its infancy and was a small portion of retail revenue situs directly assigned to each customer class. Exported energy from on-site customer-generators reduces net power cost ("NPC") by reducing purchases or fuel costs. While these cost savings reduce NPC which is captured in the ECAM, the cost of paying for exported energy that is above what is built into the revenue for a general rate case is absorbed by the Company. The cost of the ECAM is allocated to customer classes on the basis of energy sales adjusted for line losses.

10.3 Export Credit Price Scenarios

The Study Scope asked the Company to quantify the annual export costs for each customer class and different assumed export rates.

Study Scope Item 23

Quantify these annual costs under the assumptions that the Export Credit Rate is the retail rate, 7.4 cents/kWh, 5 cents/kWh, or 2.23 cents/kWh.

Assuming instantaneous netting, the export credit payments by class are show in Table 10.2 for the different specified export credit prices.

Table 10.2: Annual Export Costs by Rate

	Residential Sch 1	Residential Sch 36	General Service Sch 23	General Service Sch 6	Total
Exported Energy (MWh)	8,555	2,183	565	123	11,426
Value at Retail Rate	$916,330	$269,067	$51,091	$5,242	$1,241,731
Value at 7.4¢/kWh	$633,050	$161,516	$41,835	$9,126	$845,526
Value at 5.0¢/kWh	$427,736	$109,132	$28,267	$6,166	$571,301
Value at 2.23¢/kWh	$190,770	$48,673	$12,607	$2,750	$254,800

The Study Scope called for an analysis how these costs would be allocated and recovered by each rate class through the Company's ECAM.

Study Scope Item 24

Analyze how these costs would be allocated and recovered by rate class through the Company's proposed ECAM method going forward.

Going forward, the Company recommends that the export credits paid to customer generators on the net billing program would be recorded as a purchased power expense and tracked in the ECAM like all other energy purchases. This would match the cost exported energy with any reductions to net power costs by avoided purchases or reduced fuel expense. The Company recommends that the cost of export credits would be allocated to customer classes on energy sales adjusted for line losses, which is consistent with how other ECAM costs are treated.

11.0 Schedule 136 Implementation Issues

The Study Scope asks the Company to consider several implementation issues such as billing structure for on-site generators, export credit expiration scenarios, and the frequency of export credit updates.

11.1 Billing Structure

11.1.1 Time-of Delivery Pricing

The Study Scope requested an explanation of how seasonal and time-of-delivery price differences will be used to help match up customer generated exported energy with the Company's needs and how using more granular time periods for energy and capacity credits could be used to match up customer-generated exports more closely with the Company's system needs.

Study Scope Item 25

Explain if and how seasonal and time-of-delivery price differences will be used to help align customer generated exported energy with the Company's system needs.

Study Scope Item 26

Explain if and how using more granular time periods for differentiating energy and capacity credits could be used to more closely align customer-generated exports with the Company's system needs.

There are both pros and cons to setting the price for export credits based upon season and time of use period instead of using a flat, year-round export credit price that is the same in all hours. Using prices that vary by period, seasonal and time of use, provides a more accurate price signal that may help customers optimize both their generation design and their usage habits. For example, a higher on-peak export rate may encourage a customer to deploy west facing solar panels that produce more during high value evening periods, or a customer might make a stronger effort to use energy during lower cost middle of the days times. However, the difference between retail rates for energy taken from the grid as compared to a flat export price may provide sufficient incentive to do this anyways. All the Company's Idaho customers are subject to electricity prices that vary based upon season, but most customers are not on a time of use option. Making prices more granular may be confusing to customers and may make the decision whether to build onsite generation or not a more difficult decision to make. Table 11.1 below lists the pros and cons of seasonal and time of use export credit pricing as compared to flat export credit pricing:

Table 11.1: Pros and Cons of Seasonal and Time of Use Export Credit Pricing

Seasonal Export Prices	**Pros**	**Cons**
	More Accurate Pricing	More Confusing for Customers
	Consistent with Seasonality for the Price at which Customers Buy Energy from the Grid	More Difficult to Make a Decision About Adopting Onsite Generation
Time of Use Export Prices	**Pros**	**Cons**
	More Accurate Pricing	More Confusing for Customers
	Sends a Price Signal to Optimize Deployment of Generation and Energy Usage Habits	More Difficult to Make a Decision About Adopting Onsite Generation
		Inconsistent with Price Paid for Energy Since Most Customers are Not Subject to Time of Use Pricing

Table 11.2 below shows what the export credit price in 2025 would look like based upon the export credit values on Table 4.1 if it were flat, seasonal, time of use, or seasonal and time of use. Note that each of the four time of use period definitions shown result in the same compensation for a customer whose exports align with the average export profile. Customers who are able to export more during on-peak and/or summer periods would receive higher compensation with differentiated rates.

Table 11.2: Illustrative Export Credit Prices Under Different Modes of Time Granularity

Pricing Mode	¢/kWh	Jun-Oct ¢/kWh	Nov-May ¢/kWh	On-Peak ¢/kWh	Off-Peak ¢/kWh	Jun-Oct On-Peak ¢/kWh	Jun-Oct Off-Peak ¢/kWh	Nov-May On-Peak ¢/kWh	Nov-May Off-Peak ¢/kWh
Flat	2.30								
Seasonal		3.22	1.62						
Time of Use				4.89	1.93				
Seasonal & Time of Use						5.26	2.57	2.99	1.57

Whether the credit is set using a seasonal, time of use, or a hybrid approach, it is recommended that the ECR would be the same for all customer classes with on-site generation including residential, general service, and irrigation customers. Keeping the same ECR for all classes would minimize complexity and potential customer confusion.

11.1.2 Economic Evaluation for Customer-Generators and On-Site Generation System Installers

The Study Scope requested an explanation of how potential customer generators and on-site generation system installers can have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system.

Study Scope Item 27

Explain how potential customer-generators and on-site generation system installers will have accurate and adequate data and information to make informed choices about the economics of on-site generation systems over the expected life of the system.

The purpose of customer generation programs like net metering or net billing is to offset part or all the Customer's own electrical requirements and not to enable customers to become an independent power producer. If the customer's intent is to offset its own usage, then customer generators and system installers have the same customer usage information and pricing to make informed choices about the economics of on-site generation systems as they do to make decisions about other energy investments like conservation focused measures such as more efficient windows or air conditioning equipment. Under net billing, customer-generators would be encouraged to match up their usage with generation. This can be done behaviorally through actions such as running appliances like dishwashers during the middle of the day, sizing their systems at levels that reduce exports, or installing onsite storage. A customer can ask the company that is selling the renewable generation equipment for an estimate of hourly expected energy output. An estimate of hourly solar production can also be obtained from the

National Renewable Energy Laboratory's PVWatts tool[21]. With the installation of AMI, customers are able to view their hourly usage online which should allow determined customers to analyze their usage patterns.

11.1.3 Residential Solar Energy Disclosure Act

The Study Scope requested an explanation of how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.

Study Scope Item 28

Explain how on-site generation system installers will be able to comply with the Residential Solar Energy Disclosure Act if hourly or instantaneous netting and/or granular time-differentiated export rates are adopted and updated annually.

As explained in response to Study Scope item 27, the intent of net metering or net billing is not for customers to become developers of qualifying renewable generation resources or to get into the business of selling energy to the Company. The purpose is to offset the customer's own usage. Inasmuch, as net billing customers use the generation they produce onsite, they will avoid paying the retail price for energy. When customer generators send export energy to the utility grid, they will be compensated at the export credit price which would update periodically. The value of exported energy could change over time. Before committing to install onsite generation, customer generators should take note that all investments including rooftop solar have risks. While under net billing, a customer generator will save on their utility bill from producing energy, those savings may go up or down with time. In many ways installing onsite generation is like choosing to purchase a hybrid or electric vehicle. An individual who makes this choice would save on gasoline over time, but those savings levels fluctuate with the changing price of gasoline. Under the Residential Solar Energy Disclosure Act, installers will need to document for their potential customers the assumptions used in their projection of savings for the system.

11.2 Export Credit Expiration

To evaluate different scenarios for export credit expiration, the Study first evaluated the current magnitude of accumulated export credits and generation. Then, the effects of different expiration periods were analyzed to see how customers would be affected. Finally, the Study looked at how the Company and non-participating customers are impacted by expired credits.

11.2.1 Accumulated Export Credits

The Study Scope requested the magnitude, duration, and value of accumulated export credits as of August 1, 2020, be quantified.

[21] See https://pvwatts.nrel.gov/

Study Scope Item 29

Quantify the magnitude, duration, and value of accumulated export credits as of August 1, 2020.

As of August 1, 2020, there was a total of 4,530,405 kWh in excess generation for all customers as detailed in Table 11.3 below

Table 11.3: Excess kWh Total as of 8/1/2020

Customer Class	2013	2014	2015	2016	2017	2018	2019	2020	Total
Residential	21,729	46,758	59,349	140,598	215,748	631,720	1,141,045	1,226,213	3,483,160
Small Commercial	41,462	70,153	61,235	92,809	158,167	245,993	195,306	163,280	1,028,405
Large Commercial	-	80	240	440	320	1,040	2,560	14,160	18,840
Irrigation	-	-	-	-	-	-	-	-	-
Total	63,191	116,991	120,824	233,847	374,235	878,753	1,338,911	1,403,653	4,530,405

To better understand the magnitude, duration, and value of the excess generation, the Company valued each year's excess generation by customer class and rate. In addition to the table above, the Company evaluated expired generation from August 1, 2020, to December 31, 2022, to provide a more current view of expired credits. This detail is provided on the summary tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022. The estimated value of all excess generation is $325,386.06 for all 2,196 net metering customers from 2012 to 2022.

11.2.2 Impact to Customers over Various Expiration Periods

The Study Scope requested the impact to customers of a 2-year, 5-year, and 10-year expiration periods be quantified.

Study Scope Item 30

Quantify the impact to customers of a 2-year, 5-year, and 10-year expiration periods.

The impact to customers for credits expiring at either 2-years, 5-years, and 10-years, will vary depending on each customer's load and system size. Customers with systems that consistently overproduce, will be most affected by expiring credits. As shown on the Table 11.2 below, 14 percent of on-site generation systems overproduced in 2022.[22]

Table 11.4: Percentage of Customers Overproducing Annually

Year Ending	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	2	8	10	21	29	59	122	212	215	281
Small Commercial	4	4	4	5	5	9	12	19	23	16
Large Commercial	-	-	-	-	-	-	-	1	-	-
Irrigation	-	-	-	-	-	-	-	-	-	2
Totals	**6**	**12**	**14**	**26**	**34**	**68**	**134**	**232**	**238**	**299**
Percentage	5%	9%	9%	12%	10%	10%	12%	16%	14%	14%

The average annual compensation for net overproducers has been $294 over the last 5 years.[23] A breakdown of the weighted average for each customer class for the last 5 years is included in Table 11.5 below. The net value of overproduction for each of the overproducers is provided in detail in Appendix 11.1: Weighted Average Overproduction.

[22] Additional analysis included on the customer count tab of Appendix 11.2: Idaho Expired Credit Analysis 2012-2022.
[23] See summary tab of Appendix 11.1: Weighted Average Overproduction.

Table 11.5: Weighted Average of Customer Overproduction

Year Ending	2018	2019	2020	2021	2022
Residential Count	59	122	212	215	281
Average Annual Compensation/Customer	$276.02	$209.22	$196.26	$207.12	$200.37
Small Commercial Count	9	12	19	23	16
Average Annual Compensation/Customer	$1,937.71	$875.56	$785.77	$499.72	$615.28
Large Commercial Count	-	-	1	-	-
Average Annual Compensation/Customer	-	-	$842.27	-	-
Irrigation Count	-	-	-	-	2
Average Annual Compensation/Customer	-	-	-	-	$54.08
Total Customer Count	68	134	232	238	299
Weighted Average Annual Compensation/Customer	$495.95	$268.89	$247.33	$235.40	$221.60

To better understand how the overproducing customers would be impacted by different expiration periods, the Company took a sample of the overproducing customers and calculated the value of credits that could be subject to expiration over the different time periods. The results of this analysis can be seen on Appendix 11.3: Customer Impact at 2-, 5-, and 10-Year Expiration.

As shown on the residential tab of Appendix 11.3, only two customers overproduced for the year in 2013. At the end of the 10-year period, those two customers would have $1,177.5 in combined credits that would begin to expire, on a rolling basis.

For the 5-year analysis, the two customers from the 10-year analysis were analyzed again along with the largest overproducer in 2018. The overproducing site was selected to show how customers with both large and small amounts of overproduction would be affected by expired credits. As shown on the residential tab of Appendix 11.3, two of the customers would not have any expired credits when looking at the last five years, however the largest overproducer would have $9,927.32 in credits that would begin to expire on a rolling basis of approximately $2 thousand annually. While the impact to this customer could potentially be significant, most customers would not be heavily impacted by the expiration of credits over a 5-year period.

For the 2-year analysis, the customers from the 5-year analysis were included and added a customer that was at the median range for overproducers to analyze the impact to the broadest possible range of overproducers. The average annual credit of the four selected customers was $82 that would expire on a rolling basis.

In summary, over 85 percent customers will not be affected by expiring credits. For those overproducers with credits at risk of expiration, the impact will vary depending on system size and load. The most over-sized customer could see credits valued at approximately $2 thousand expiring annually. In contrast, the average overproducer would not have more than $100 in credits expire on an annual average basis.

11.2.3 Export Credit Expiration Policy

The Study Scope requested an explanation of the need for credits to expire.

Study Scope Item 31

Explain the need for credits to expire. a. Show how the Company does or does not benefit from the expiration of customer export credits. b. Show how non net bill customers are harmed or benefited from the expiration of customers export credits.

Customer generation programs are intended for customers to offset some or all of their energy bill with onsite generation and not for a customer to become a power producer. The intention of credit expiration is to encourage customers to size their generation systems to match actual usage at the site of the system.

When establishing net metering the Commission confirmed that: "The purpose of net metering is not to encourage excess generation. Developers of qualifying renewable generation resources who wish to get into the business of selling energy to the Company should, under PURPA, request firm or non-firm energy purchase contracts."[24] The net metering rate is not intended to encourage participants to become independent power producers. If the ECR is not set at a level that holds other customers economically indifferent from paying for the exports or another comparable source of energy, other customers are harmed by having to pay an unreasonable rate.

11.2.4 Treatment of Financial Credits

There are different ways financial credits generated from excess exported energy can be treated considering how they can be payable to the customer, transferrable to other meters, and how they can be applied to different charges. Presently, customer generators may use their excess credits to offset any/all charges. Excess credits are paid out to the customer generator when they discontinue service with the Company. Excess credits may only be transferred to same customer's other metered sites if the meter is located on or contiguous to

[24] *In the Matter of the Petition of NW Energy Coalition and Renewable Northwest Project to Establish Net Metering Schedules for PacifiCorp.* Case No. PAC-E-03-4, Order No. 29260 at p. 6.

the premises, served by the same primary voltage circuit, and on the same rate schedule as the meter where the excess credits were generated. A $10 administrative per meter fee is charged for transferring those credits.

There are pros and cons to different treatments of excess exported credits. The advantages of allowing the credits to be payable to a customer generator when they discontinue service are that it is seen as fairer to the customer, and potentially creates less customer complaints. The disadvantages of paying out credits when service is discontinued are that it increases the cost to non-participating customers, it can increase administrative burden for the utility, and it may encourage a customer to oversize its generation system instead of sizing its system to meet its own usage needs. There are similar advantages and disadvantages for allowing credits to be transferrable to different accounts and for allowing the credits to apply to all charges instead of only being able to apply them against energy charges. Table 11.5 lists the pros and cons of excess credits being payable at account closing, transferrable to other meters, and able to offset any charge.

Table 11.6: Pros and Cons of Different Treatments for Financial Credits from Excess Exported Energy

Credits Payable at Account Closing	**Pros**	**Cons**
	Fairness to customers who generated the credits	There is some administrative burden with issuing checks when the account closes
	Less customer complaints	Paying out the credits may encourage customers to oversize their systems
		Paying out the credits increases cost for non-participants
Credits Transferrable to Other Accounts	**Pros**	**Cons**
	Customer satisfaction for customers with multiple meters on their account	Administrative burden of transferring credits
		May encourage customers to oversize their systems
Credits Applicable to All Charges	**Pros**	**Cons**
	Less customer complaints	May encourage customers to oversize their systems

11.2.5 Treatment of Existing Credits for Non-Legacy Customer Generators

Currently, credits for excess exported energy for non-legacy (Schedule 136) customer generators are valued at the full retail value of energy charges and held on the customer's account as a financial (not a kWh) credit. These credits never expire and are paid out when the customer closes its account. This treatment ensures fairness for the customer generator. A further change could be made to allow those credits to be transferrable to any account. This would give non-legacy customer generators even more flexibility to make use of their excess export credits.

11.3 Export Credit Updates

An export credit can be updated at different frequencies such as every year or every other year. Updating more frequently can make the price more accurate since it uses more current information. Updating more frequently can also require more administrative burden for the utility and for the Commission and stakeholders who review the filing.

One option is to update some parts of the price more frequently and other parts of the price less frequently. The Company does this for its export credit price in Utah. While the export credit price in Utah is updated every year, only the energy value and the hourly export shape change every year. Other components such the integration cost or capacity value change only with new IRPs. Changes to the methodology can be changed, but take a longer review process.

11.3.1 SAR Energy Rates Updates and IRP Cycle Impact to Export Credit Updates

The Study Scope requested the impact of biennial updates, as compared to annual updates of the ECR, by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle and two IRP cycles be quantified.

Study Scope Item 32

Quantify the impact of biennial updates as compared to annual updates of the Export Credit Rate by comparing the changes in the SAR energy rate, line losses, and integration costs using historical data over one year, one IRP cycle (two years), and two IRP cycles (four years).

Assuming the ECR is updated based upon non-levelized annual prices, the Company analyzed how compensation would vary for a customer generator who exports 5,000 kWh per year under different update scenarios – annual, biennial, and every 4 years. The chart below in figure 11.1 shows how the price would have varied under these cycles starting with the prices effective around June 1, 2012, for a ten-year period:

Figure 11.1: Frequency of Export Credit Updates[25]

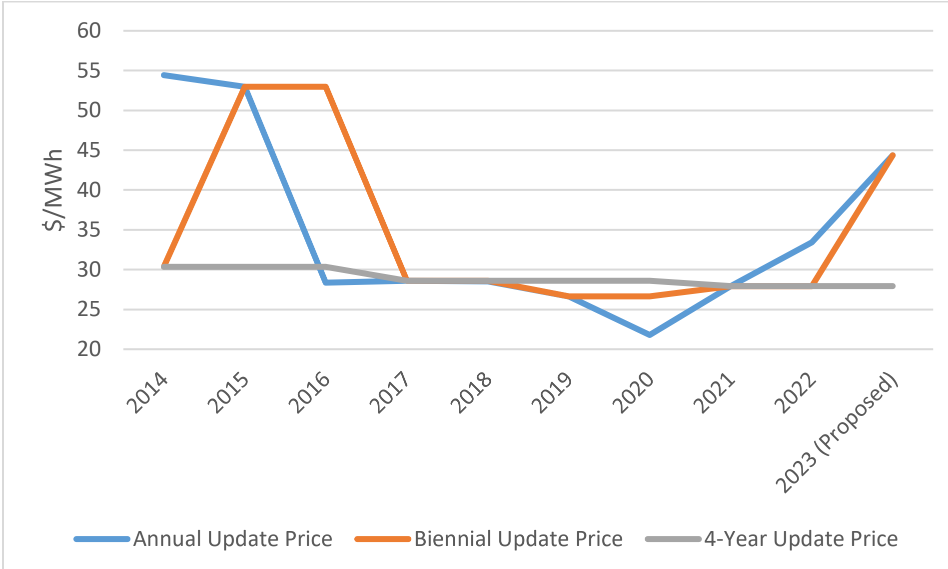


Table 11.7 shows how compensation for an annual 5 MWh of exports over this ten-year period would have compared for the different update cycle scenarios:

Table 11.7: Impact of Different Update Cycles

Annual Update Price	Biennial Update Price	4-Year Update Price
$1,735	$1,735	$1,446

The results for the annual update and the biennial update are nearly identical. The 4-year update is lower primarily, because it misses capturing higher prices that occurred in 2014 and 2015 that get picked up in annual and biennial updates. Depending upon when updates begin could make a large difference for multi-year updates in the future. Updating the ECR annually would provide customer generators with more accurate compensation.

For Rocky Mountain Power, there would be benefits to matching up the timing of export credit price updates in Idaho with Utah. In Utah, Rocky Mountain Power makes a filing with the Utah Public Service Commission on or around the end of January each year for export credit prices that go into effect on March 1.

12.0 Smart Inverter Study

The Study Scope requested an explanation of the Company's Utah smart inverter policy and a quantification of the benefits of applying that policy to its Idaho service territory.

Study Scope Item 33

Explain the key aspects of the Company's Utah smart inverter policy and quantify the benefits

[25] See Appendix 11.4: SAR Export Credit Analysis for calculation

of applying that policy in its Idaho service territory, in particular, the potential benefits of reactive power control.

In 2017, Rocky Mountain Power took part in a Smart Inverter Project as part of the Utah Sustainable Transportation and Energy Plan ("STEP") to investigate the capabilities and impacts of smart inverters on the Company's distribution system. The Company's project partners included the Electric Power Research Institute and Utah State University and resulted in the study of: (1) IEEE 1547 smart inverter standards and policy, (2) laboratory selection and testing, (3) hosting capacity results, with and without smart inverters, (4) settings determination, (5) deployment best practices, and (6) Technical Policy 138, interconnection standard updates. The Smart Inverter Study was produced from the efforts of the STEP project in Utah docket 19-035-17 and is included with this Study as Appendix 12.0: Utah STEP - Smart Inverter Study.

This research produced the smart inverter policy that the Company has implemented for its Utah customers. That policy was considered in a Utah Public Service Commission proceeding to determine how the value provided by customer smart inverters should be included in the ECR, Utah Docket No. 17-035-61, and no specific export credit value was applied to account for the benefits of smart inverter technology.

While smart inverters are not expected to impact export credit rates, including minimum requirements for inverter technology can ensure the hosting capacity and power quality of the distribution system do not get worse as customer generation is added.

The following Appendices are voluminous and provided in their native format via Box:

Appendix 3.1: Customer Generator Export and Generation Information

Appendix 4.1: Export Profile Jan21-Dec22

Appendix 4.2: Export Credit Calculation

Appendix 4.3: Customer Generation Exports During Peak Loads

Appendix 4.4: Idaho Export Profile Validation Avg Capacity

Appendix 4.5: ID Export Profile Validation Monthly Exports

Appendix 4.6: ID Export Profile Validation PV Watts Production

Appendix 4.7: Appendix K - Capacity Contribution - 2021 IRP

Appendix 7.1: PacifiCorp-Idaho 2018 Electric System Loss Study

Appendix 8.1: Appendix F - Flexible Reserve Study- 2021 IRP

Appendix 8.2: Wind and Solar Integration Charges Approved in Order No. 34966

Appendix 11.1: Weighted Average Overproduction

Appendix 11.2: Idaho Expired Credit Analysis 2012-2022

Appendix 11.3: Customer Impact at 2-, 5-, and 10-Year Expiration

Appendix 11.4: SAR Export Credit Analysis

Appendix 12.0: Utah STEP - Smart Inverter Study

CERTIFICATE OF SERVICE

I hereby certify that on this 8th of February, 2024, I caused to be served, via electronic mail a true and correct copy of Rocky Mountain Power's On-site Generation Study Supplement to the service list in Case No. PAC-E-23-17 to the following:

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Dated this 8th day of February, 2024.

Santiago Gutierrez
Coordinator, Regulatory Operations