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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT CHANGES TO THE COMPENSATION STRUCTURE APPLICABLE TO CUSTOMER ON-SITE GENERATION UNDER SCHEDULES 6, 8, AND 84 AND TO ESTABLISH AN EXPORT CREDIT RATE METHODOLOGY	CASE NO. IPC-E-23-14 VOTE SOLAR'S REPLY COMMENTS REGARDING CHANGES TO ON-SITE GENERATOR'S COMPENSATION STRUCTURE AND EXPORT CREDIT RATE

COMES NOW, Vote Solar, by and through counsel, Elam & Burke, P.A., and pursuant to Rules 202 and 203 of the Rules of Procedure of the Idaho Public Utility Commission (IDAPA 31.01.01.202; 31.01.01.203) and, pursuant to that Notice of Modified Procedure, Notice of Virtual Public Workshops, Order No. 35881, filed on August 10, 2023, hereby submits its reply comments ("Reply Comments") to various parties' originally filed comments related to changes to on-site solar generation customer's compensation structure and export credit rate as follows:

I. INTRODUCTION

Vote Solar respectfully submits these Reply Comments addressing various parties' comments submitted on or before October 12, 2023. These Reply Comments relate to the proposed changes to on-site solar generating customers and the proposed export credit rate ("ECR") suggested by Idaho Power Company ("Idaho Power" or "Company"). Vote Solar's Reply

Comments respond to the initial comments of Idaho Public Utilities Commission ("Commission") Staff ("Staff"), Clean Energy Opportunities ("CEO"), the City of Boise, Idaho Conservation League ("ICL"), and the Idaho Irrigation Pumpers' Association ("IIPA"). Vote Solar's response testimony includes three sections. First, we address recommendations related to specific components of the ECR. Second, we address proposals related to rate design considerations regarding the ECR. Third, we respond to other recommendations related to the tariff language of rate schedules to which the ECR would apply. Vote Solar's lack of comments on any specific issue raised in other parties' comments or the public's testimony should not be interpreted as acquiescence or agreement with those aspects.

II. SUMMARY OF RECOMMENDATIONS

The opinions presented in Vote Solar's initial comments remain unchanged. Analysis quantifying the benefits of exported energy demonstrates that its value is comparable to, or higher than, volumetric retail rates paid by Idaho Power customers for electricity. This finding justifies the retention of an equivalent rate for energy consumption and exports for Schedules 6 and 8 and net metering for Schedule 84. Vote Solar's primary recommendation is that the Commission keep existing rates applicable to customers with on-site generation in place and monitor both solar adoption and the value of exported energy over time. This approach affords the Commission ample time to develop a structured plan for transitioning to new rates when solar adoption reaches higher levels of saturation. This approach also ensures the public is adequately prepared for a transition and gives prospective solar customers visibility into what rates will look like in the future.

Should the Commission elect to adopt an avoided cost-based financial credit rate for energy exports, the ECR must account for the full range of avoided costs that result from exported energy, including avoided energy costs, avoided generation capacity costs, avoided transmission and distribution costs, avoided fuel cost risk, and quantifiable avoided environmental costs.

Should the Commission approve an avoided cost-based export rate, Vote Solar recommends that the Commission strike a balance between reliance on the best available data, stability and simplicity. A real-time, time-varying export rate that updates annually is a substantial departure from the current rates applicable to customers with distributed generation. Regulatory decisions that increase complexity or do not provide customers with clarity about the future introduce risk and uncertainty about the value of a long-term investment in distributed generation. The Commission heard this from countless customers at the Customer Hearing on October 24, 2023. When individual customers choose to invest their own capital in distributed generation, it provides substantial long-term benefits to all ratepayers, as outlined in Vote Solar's initial comments.[1] In the interest of creating a supportive environment for customers interested in adopting distributed generation, Vote Solar recommends that the Commission approve a flat annual average ECR of 10.04 cents per kilowatt-hour as the default offering, along with an optional time-differentiated ECR available to customers at their discretion. Vote Solar also recommends that the ECR be locked-in for individual customers for a period of at least 10 years.

To fairly account for the full suite of benefits provided by exported energy from customers with on-site generation, the ECR must include at minimum quantification of avoided energy costs, avoided line losses, avoided generation capacity costs, avoided distribution and transmission capacity costs, avoided fuel price risk, and quantifiable environmental attributes. Additional detail regarding quantification of these ECR elements is discussed in Section III.

Finally, Vote Solar requests that the Commission recognize that customers who have

[1] IPC-E-23-14 Vote Solar Initial Comments at 11 – 13.

installed solar since the conclusion of IPC-E-18-15 have made investments in solar installations that are configured based on the best information available to those customers at the time. These existing solar customers could not have anticipated the final ECR value or determined how to optimize their solar installation to account for the on-peak and off-peak periods defined in the ECR. Vote Solar requests that customers who have already applied to interconnect solar (or made a financial commitment to install solar) before the date of the Commission's final order in this docket be permitted to remain on the rate current at the time of their application for 20 years.

III. ANALYSIS OF THE PROPOSED EXPORT CREDIT RATE

Vote Solar's initial comments presented corrections to the ECR that result in a value of 10.04 cents per kilowatt-hour. This ECR value is conservative because it does not account for additional benefits that accrue to utility customers in Idaho from on-site generation, including health and social benefits and improving the utility's ability to timely comply with future environmental regulations. Since that time, parties to Idaho Power's ongoing General Rate Case have filed a Settlement Stipulation.[2] Although the Settlement has not yet been approved by the Commission, I compared Vote Solar's ECR value with updated volumetric retail consumption rates that would be applicable to Schedule 6 and 8 customers at the end of the proposed Rate Case transition period, as shown in Figure 1.

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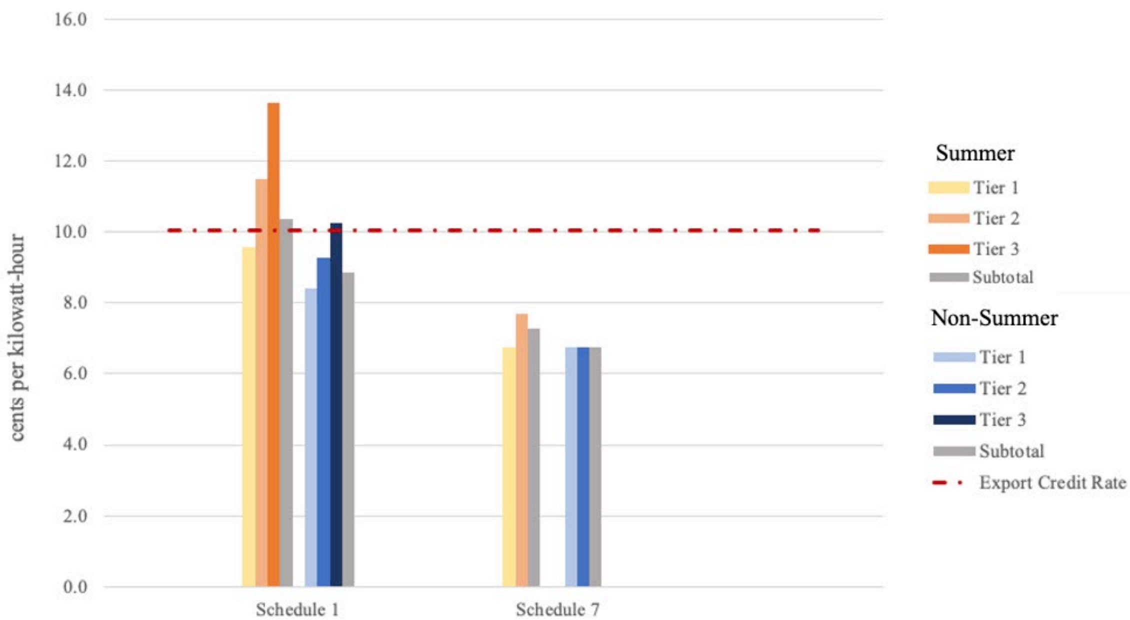
[2] IPC-E-23-11, Idaho Power Company's General Rate Case, Motion for Approval of Stipulation and Settlement, October 27 2023.

Figure 1. Comparison of Proposed Schedules 1 and 7 in 2025 to Export Credit Rate



Based on the rates proposed to be effective in 2025, the volumetric retail rate applicable to Schedule 1 and 7 customers will be lower than the value of exported energy in non-summer months. During the summer, the average rate applicable to Schedule 1 customers is comparable to the value of exported energy. Given this comparison, it is just and reasonable to retain an equivalent rate for energy consumption and exports for Schedule 6 and 8 customers. This approach provides customers with a simple and easily understandable opportunity to reduce their utility bill through energy exports.

1. Avoided Energy Costs

Vote Solar's initial comments identify changes necessary to improve the accuracy of the energy value of the ECR, including a revision to the avoided line loss value to reflect marginal losses and use of an integration cost that is reflective of Idaho Power's actual system resource mix, both discussed below. Vote Solar also supported using an energy value based on a three-year rolling historical average of market prices, an option presented by Idaho Power in its VODER study.[3]

a) *The Export Credit Rate should not vary based on the customer that exports energy.*

IIPA recommends creating a separate ECR applicable to irrigation customers, where the energy component of the ECR is calculated based the specific export profile of irrigation customers with on-site generation (IIPA Comments, October 12 2023 at 3). IIPA states that this result "will better align the value of exports with the rate classes producing the exports" (IIPA Comments, October 12 2023 at 6).

Vote Solar does not agree with this approach. The value of exported energy varies based on the time and location of its generation, but does not vary based on the type of customer who generated the power. Idaho Power's proposed ECR is an avoided cost based financial credit that accounts for the value of energy, generation capacity, transmission and distribution capacity, and line losses that are avoided when customers with on-site generation export power to the grid. The type of customer who has exported the electricity has no bearing on the value of the electricity to the utility. Further, load profiles vary substantially even among customers within a class, and intra-class load diversity will likely increase as battery storage adoption becomes more common. Time-varying consumption or export rates provide a price signal that encourages customers with storage to dispatch their batteries during high-cost periods. Under this paradigm, the distinction between load profiles of customers with and without storage could be much more substantial than load profile differences that exist between classes. IIPA's proposal introduces complexity without meaningfully improving the precision of the ECR. Finally, IIPA's proposal is counter to the goals

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[3] IPC-E-22-22, 2022 VODER Study, October 2022, Section 4.1.1.3, *available at:* *https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2222/CaseFiles/20221026_Voder%20Study_Clean.pdf*.

of developing a time-differentiated export rate because it weakens the price signal encouraging non-irrigator customers to export energy during times when it is most valuable.

b) *Distributing avoided energy value in alignment with summer and non-summer seasons adds complexity with minimal benefits.*

Staff recommends allocating the avoided energy value of the ECR in alignment with the summer and non-summer seasons, rather than on-peak and off-peak time windows (Staff Comments, October 12 2023 at 18). Staff notes that energy costs are higher in the summer season, including outside of the on-peak window. A downside of this approach, which Staff also discusses, is that the ECR could have as many as four values: a summer on-peak value, a summer off-peak value, and non-summer on-peak and off-peak values. Staff believes "this small additional complexity is worth the benefits" (Staff Comments at 19), but Vote Solar does not agree that this approach benefits customers with or without solar. The small increase to the ECR during summer off-peak hours, from 4.91 cents per kilowatt-hour in Idaho Power's proposal to 5.66 cents per kilowatt-hour in Staff's proposal, will not substantially improve the economics of exporting power during this period. However, the corresponding decrease to the ECR value during summer on-peak hours weakens the price signal encouraging customers to export energy during those hours. Instead, Vote Solar continues to recommend providing customers with a choice between a flat annual average ECR and a time-differentiated ECR that includes on-peak and off-peak periods, as described in Vote Solar's initial comments (Vote Solar Comments, October 12 2023 at 34). Both rate designs accurately reflect the value that exported energy provides to the grid over the course of a year. The flat average annual rate offers simplicity for customers who have limited ability to shift their exports to a different time of day. The time-differentiated rate provides more sophisticated customers with an opportunity to further reduce their bill by adopting storage and dispatching their storage equipment during the hours when it is most valuable.

c) *A balancing account as proposed by IIPA is unnecessary.*

IIPA proposes to create a balancing account to track the difference between the energy value paid to customers and the value received from customers (IIPA Comments at 10). IIPA argues that since the energy component of the ECR is based on historical prices, it could result in Idaho Power overpaying if energy prices fall relative to the historical price used to set the ECR. Vote Solar does not agree with the assertion that using historical energy prices to calculate the ECR will cause Idaho Power to overpay for energy. The energy value of the ECR is calculated based on actual exports and actual hourly energy prices, so it accurately reflects the value that customers who exported solar energy provided to the grid during a historical period. Because of the lag inherent in reliance on historical prices, customers who export energy to the grid effectively receive compensation today based on the value they provided to the grid a year ago. This delay can just as easily result in an ECR that underpays for electricity. Recent history shows that the presumption that energy prices will always be lower in the future is flawed. Energy prices in 2022 were higher than previous years, and remained elevated in early 2023.[4] If energy prices rise, then a customer subject to an ECR calculated during a period of lower energy prices is being undercompensated for the energy they export to the grid. Given the small amount of power that is exported by customers with on-site generation and the reality that energy prices are just as likely to rise from year to year as they are to fall, a balancing account is unnecessary.

[4] California ISO, "Q1 2023 Report on Market Issues and Performance," September 19, 2023. Figure 1.10 Monthly load-weighted average energy prices for California ISO at 13. *Available at:* http://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf.

2. Avoided Line Losses

As described in Vote Solar's initial comments, energy exported by on-site generation helps to reduce utility costs on the margin, and the line losses associated with marginal additions of load are substantially higher than average line losses (Vote Solar Initial Comments at 17). In place of the line loss values provided by Idaho Power, Staff recommends the use of industry-typical line loss calculations based on a U.S. Energy Information Administration analysis of estimated losses for Idaho. Staff's recommendation does not address the key shortcoming of Idaho Power's line loss calculation, as both Staff and the Company's methods rely on average line losses and not marginal line losses. The Company- and Staff-proposed line loss coefficients are between 4.4 and 5.3 percent, but marginal line losses are typically twice as high as average line losses and can be as high as 15 to 20 percent.[5] Vote Solar recommends that the Commission disregard Staff's line loss coefficient proposal and find that the ECR must accurately account for avoided marginal line losses.

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[5] *For a hypothetical utility with average resistive losses of about 7% over the course of a year and peak losses of 11%, marginal resistive losses – "those that would be avoided if load had been a little bit lower" – are 20%.*

Regulatory Assistance Project, "Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements." *Available at: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf,* pages 4 - 5.

"Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the 'true reduction in losses on a marginal basis.' Considering losses on a marginal basis is more accurate and should be standard practices as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses… In practices this can equal l5 – 20% of the energy value."

IREC, "A Regulator's Guidebook: Calculating the benefits and costs of distributed solar generation. October 2013. *Available at: https://irecusa.org/resources/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/,* pages 23 – 24.

3. Integration Costs

Vote Solar's initial comments recommend the Commission approve integration costs for Case 9 from the 2020 Variable Energy Resources ("VER") Study conducted by E3, which accounts for the addition of 200 MW of storage. In addition to the 120 MW of storage projects identified in Vote Solar's initial comments, CEO's initial comments describe a 60 MW battery storage system anticipated to come online in 2024, for a total of 180 MW of battery storage (CEO Comments, October 12 2023 at 8). The integration costs calculated for Case 9 are a more accurate representative of actual integration costs on Idaho Power's system compared to Case 1, which does not include any storage.

4. Avoided Generation Capacity Costs

a) Only Vote Solar's proposed generation capacity costs comply with Order No. 35631

In initial comments, Vote Solar presented an avoided generation capacity cost based on the capital cost of the next planned dispatchable resource in the Company's 2021 IRP, a battery storage project with a generation capacity cost of $192 per kW-year.[6] Vote Solar's calculation also accounts for avoided line losses and Idaho Power's planning reserve margin, because when load is reduced by a kilowatt, the amount of generation the utility must procure is reduced by a kilowatt plus its planning reserve margin. Idaho Power's proposed generation capacity cost is based on the capital cost of a simple cycle combustion turbine from the Company's 2021 Integrated Resource Plan, which is $106.19 per kW-year. Staff's initial comments recommend use of the least expensive dispatchable resource from the 2023 IRP, a simple cycle combustion turbine with a cost

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[6] Idaho Power, "Integrated Resource Plan," December 2021, Appendix C, *available at:* https://docs.idahopower.com/pdfs/AboutUs/PlanningforFuture/irp/2021/2021_IRP_AppC_Technical%20Report_WEB.pdf, *page 47.*

of $145.94 per kW-year (Staff initial comments at 20). As noted in Vote Solar's initial comments, the Commission's Order No. 35631 stated, "we note the importance of an avoided generation capacity value that accurately considers capacity costs *actually avoided* [emphasis added]" (Order No. 35631 at 29). Use of the least expensive resource available for selection in the Company's IRP, regardless of whether or not that resource is actually selected, does not comply with Order No. 35631. Exported energy from on-site generation facilities reduces the total system load that Idaho Power must plan to serve, offsetting growth in customer load and allowing the Company to build the next planned generation resource later than would have been required without the contributions of on-site generation. The capacity costs that on-site generation actually avoids are the levelized capacity costs of the next incremental resource the Company plans to build to meet growing customer demand. Idaho Power's Preferred Portfolio does not call for the addition of new simple cycle combustion turbine resources, and so on-site generation cannot avoid the cost of a resource that the Company does not plan to build. The only gas resources included in Idaho Power's 2023 Preferred Portfolio are conversions of coal resources to gas, including 357 megawatts of gas conversions in 2024 as a result of the planned conversion of Bridger units 1 and 2. The purpose of the planned gas conversions is not to meet an identified capacity need, but rather to continue serving existing customer demand with reduced emissions, reduced operations and maintenance costs, reduced capital costs, and increased flexibility.[7] Presumably, the Company would not defer the conversion of coal resources to gas when doing so saves its customers' money and improves flexibility. The incremental resource addition that on-site generation actually avoids is battery storage. Vote Solar's recommended avoided generation capacity cost is the only proposal

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[7] Idaho Power, "Integrated Resource Plan," September 2023, *available at:* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-irp-final.pdf, page 61.

that complies with the Commission's Order No. 35631

b) *The ECR must include quantification of avoided generation capacity costs.*

IIPA proposes that the ECR should not include a capacity value because use of EIM prices as a proxy for the avoided energy value double counts the avoided capacity costs. This perspective misconstrues the differences between avoided energy costs and avoided capacity costs, and conflates the business models of merchant generators with that of Idaho Power. The capacity value and the energy value components of the ECR represent two distinct value streams. The generation capacity value reflects the capital cost required to build a power plant, which can be deferred when customers invest their own capital in constructing energy resources that are used to serve Idaho Power customers. The energy value represents the cost incurred to operate a power plant in order to generate electricity, including fuel, or alternatively the cost of purchasing energy on the market. Idaho Power incurs both generation capital costs and energy costs to deliver power to customers.

As previously discussed, EIM prices are a reasonable proxy for the avoided energy costs that result from solar exports. EIM prices are differentiated based on time and location, so they accurately reflect the variable value of energy throughout the year. In contrast, the avoided generation capacity value represents the cost Idaho Power incurs to procure capacity to serve its customers. Capacity is the maximum power output a resource is capable of providing reliably when it is called upon. Some utilities participate in capacity markets, where a power provider is compensated for committing that a certain amount of capacity will be available if called upon several years in the future. In contrast, the EIM is a real-time energy supply market where participants may trade electricity in 15 minute intervals. Even when energy is purchased at a high price that reflects market constraints and scarcity, energy purchases do not come with a guarantee that energy will be available in the next hour or at any point in the future. Staff agrees with the use of hourly EIM prices as a proxy for the value of energy and specifies that "The price represents the market value of *non-firm* energy…" (Staff Comments at 17.) Idaho Power cannot obtain firm capacity resources through the EIM. In fact, a balancing authority must show that they can pass a "capacity test" by demonstrating that they have sufficient capacity resources to meet their own demand before they are allowed to participate in the EIM.

A merchant generator that participates in a real-time energy market may rely on high prices during periods of energy shortage to recover its capital costs and earn a return on its investment. However, vertically-integrated utilities acquire capacity by building and operating power plants or entering into long-term power purchase contracts. Idaho Power recovers the capital costs of its investments in power plants from ratepayers, and the upfront capital costs remain the same regardless of how much or how little a power plant is used.

Customers with on-site generation provide both energy and reliable capacity because they are captive customers of Idaho Power. On-site generation customers cannot participate in markets, and have no options to market excess power except for exporting it to the grid where it contributes to serving Idaho Power's customers' load. It is essential that the ECR account for the avoided capacity costs that energy exports from on-site generation provide as well as the avoided energy costs. Vote Solar's initial comments recommend using the cost of the next planned generation resource to determine avoided capacity costs, adjusted to account for the actual capacity contribution that exported energy provides in a given year as calculated using the capacity factor method.

5. Capacity Value

a) Idaho Power's capacity value analysis lacks accuracy and transparency.

Staff's initial comments identify three issues with Idaho Power's ELCC analysis. First, Idaho Power did not account for its battery energy storage systems ("BESS") when determining its hours of highest risk (Staff initial comments at 14). The value of using an ELCC to assess capacity value is that an ELCC accounts for the actual, specific resource mix present on the Company's system and actual load to determine capacity value based on analysis of every hour of the year. The combination of resource availability and load determine the hours in which the grid is most likely to experience energy shortfalls. As a result, ELCC results change when the resource mix changes or when load changes. Battery storage is a very flexible resource that can be dispatched as needed. Unlike conventional resources that take time to ramp up or down, battery storage can be dispatched almost instantaneously and has none of the startup costs associated with cycling a conventional resource on and off. Just as the addition of battery storage to Idaho Power's grid results in substantially lower integration costs, the dispatch of battery storage resources could have a profound impact on the system hours of highest risk. Staff is "concerned that by excluding BESS resources from the model, the analysis does not accurately reflect the actual risk seen by the system" (Staff initial comments at 14).

As part of the 2023 IRP, Idaho Power has updated its ELCC results and finds that utility-scale solar resources on the Company's system today have an ELCC of 51.3% (See Figure 2). The future solar resources that the utility plans to add to the system will have an average ELCC of 27.7%. These results indicate that the capacity value of new solar resources has increased, relative to the 2021 IRP, and that solar resources provide substantial capacity value to Idaho Power's system, now and into the future.

Figure 2. Updated Effective Load-Carrying Capability Results from Idaho Power's 2023 IRP[8]

ELCC of Existing and Expected Resources		ELCC of Future Resources	
Resource	**Average**	**Resource**	**Average**
Solar	51.3%	Solar	27.7%
Wind	20.0%	Wind (ID)	15.5%
Demand Response	34.0%	Wind (WY)	20.8%
4-Hour Stand-Alone Battery Storage	81.2%	4-Hour Stand-Alone Battery Storage	38.5%
Solar + 4-Hour Battery Storage (1:1)	85.1%	8-Hour Stand-Alone Battery Storage	79.2%
Solar + 4-Hour Battery Storage (1:0.6)	61.2%	Incremental Existing Demand Response	19.4%
		Storage Demand Response	35.0%
		Pricing Demand Response	32.2%

Second, Staff disagrees with one of the Company's ELCC calculation steps, in which the Company manipulated the on-site generation customer export profile to remove all customer exports during off-peak hours before inputting it into the ELCC algorithm (Staff initial comments at 21). The purpose of an ELCC is to provide a granular analysis of a resource's ability to reliably serve energy demand during every hour of the year, but if the export profile used as an input to the ELCC only accounts for exports during the hours that fall within the on-peak window then the ELCC results will not accurately account for the capacity contribution of on-site generation exports throughout the year.[9]

Third, Staff believes that the ELCC algorithm effectively nullifies the impact of avoided line loss increases because it does not have the resolution to account for such small differences in

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[8] Idaho Power 2023 IRP, September 2023, Appendix C *Available at:* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-appendix-c-final.pdf, page 92.

[9] The Company's response to Staff Production Request No. 2 references an excel file that contains "the hourly customer generator exported energy values and the corresponding line loss factor calculation" used to calculate the capacity contribution portion of the avoided generation capacity value. The corresponding excel file, "Attachment – Response to Staff Request No. 2" includes exports only during the 624 hours of the year included in the on-peak window.

exports (Staff Comments at 21). Staff has proposed a workaround to ensure that line losses are accounted for by applying the line loss gross up after first using the ELCC to determine capacity value. However, given the very small amount of exported on-site generation in Idaho Power's service territory – less than 1% of the utility's total retail sales[10] - it is essential to use a capacity value method that is granular enough to capture small changes in exports.

The issues identified by Staff highlight the challenges that come with using a capacity value method that is not transparent and easily reviewable by stakeholders. As Staff describes, "because the Company performs these calculations using complicated MATLAB scripts, verification by Staff is extremely difficult" (Staff initial comments at 21). If subject matter experts, such as Staff, are finding Idaho Power's calculations and methodologies "extremely difficult" it will be surely impossible for customers to understand the methodologies.

Instead, Vote Solar has proposed a methodology for calculating capacity value that is both sufficiently accurate to estimate the capacity value from on-site generation and much simpler and more transparent. Staff expresses skepticism about this methodology because it assesses a resource's contribution during hours of highest system load rather than focusing specifically on the periods of highest risk (Staff initial comments at 20). To evaluate this, Vote Solar reviewed the distribution of the top 10% of high load hours used to calculate the capacity value Vote Solar recommended in initial comments. Vote Solar found that over 99% of high load hours occur in the months of June through September, the same seasonal period when the hours of highest risk occur.

[10] Distributed solar customers exported 92,076 MWh of electricity in 2022 and Idaho Power reported annual retail sales of 15,882,445 MWh in 2022.

Vote Solar does not entirely agree with Staff's claim that "the true value of avoided capacity occurs during the hours of highest risk" (Staff initial comments at 20). While it is prudent and appropriate for utilities to evaluate hours where loss of load risk is highest and procure resources that ensure adequate electricity supply is available throughout the year, high load hours are also a key driver of capacity costs. If system peak load increases, then Idaho Power must construct or procure new capacity resources to reliably serve customer energy demand. The cost allocation methodologies currently used by Idaho Power assign system costs to customer classes based on each respective classes' contribution to system peak load. Generation demand and transmission costs are allocated to customers based on usage during the 12 monthly coincident peaks, and generation peaking unit costs are allocated based on the coincident peak during the 4 summer months of June through September.[11] Use of high load hours to calculate the value of contributions from exported energy is aligned with the methodologies that are currently used to assign costs to Idaho Power customers.

6. Deferred Transmission & Distribution Capacity Costs

a) Avoided distribution capacity costs do not vary by customer class and should be included in the ECR for all customers.

IIPA argues that customers subject to rate schedules that recover some portion of distribution demand costs through the energy charge should not receive credit for the avoided distribution costs that result from exported on-site generation. This approach does not comport with the concept of an Export Credit Rate, which is a financial credit representing the actual value

[11] IPC-E-23-11, In the matter of the application of Idaho Power Company for authority to increase its rates and charges for electric service in the state of Idaho and for associated regulatory accounting treatment, Direct Testimony of Pawel P. Goralski, June 1 2023 at 15.

of exported energy. Just as the value of exported energy does not vary based on the type of customer who has exported energy, electricity exported by on-site generators results in avoided distribution costs when it contributes to load reductions that defer distribution system projects regardless of who has exported the energy. The value of avoided distribution capacity should be included in the ECR and apply to all customers, regardless of their rate schedule.

7. Avoided Fuel Price Risk

In initial comments, Vote Solar recommended the Commission acknowledge that exports from on-site generation provides a hedge benefit and approve an avoided fuel cost risk value equal to 5% of avoided energy costs. Clean Energy Opportunities notes that the value of price hedge benefits is not zero, and cites a Rocky Mountain Power analysis in Idaho that reports a fuel price hedge value equal to 3.9 percent of the energy value (CEO comments at 3). Vote Solar requests that the Commission find that the value avoided fuel price risk should be accounted for in the ECR.

8. Renewable Energy Credits

Several parties have expressed interest in monetizing the renewable energy attributes that result from on-site generation. The City of Boise requests that the Commission direct the Company to work with interested stakeholders to evaluate the feasibility of compensating customers for the renewable energy attributes of exported energy (City of Boise Comments, October 12 2023 at 9). Clean Energy Opportunities finds that the transfer of customers' ownership of renewable energy attributes is feasible, requests that the Company report on opportunities to monetize the value of renewable energy attributes of exports as part of the annual ECR update, and asks that a placeholder be defined for renewable energy attributes in the ECR methodology. Vote Solar is supportive of allowing customers with on-site generation to monetize the renewable energy attributes associated with their energy exports.

IV. EXPORT CREDIT RATE DESIGN CONSIDERATIONS

1. Timing of Annual Update

Vote Solar recommended that should the Commission implement an ECR, the first annual update should take place effective June 1, 2025. Staff and Clean Energy Opportunities support this timeline for the first update to the ECR (Staff Comments at 31, CEO Comments at 2.)

2. Stability of Export Credit Rate

Vote Solar has recommended that ECR rates be locked-in for individual customers with on-site generation at the rate effective at the time of the customer's application to interconnect their system for a period of at least 10 years. Idaho Conservation League notes the need to provide customers with on-site generation with stability and requests that the Commission authorize an ECR update period longer than one year (ICL Comments at 2). Vote Solar supports approval of an ECR update interval greater than one year as this will help to reduce the uncertainty inherent in a rate that is updated annually. However, even if the ECR is updated less frequently, Vote Solar continues to recommend that individual customers be permitted to lock-in their rates for 10 years, as is currently applicable to solar customers in Nevada and Arizona.

V. Other Considerations

1. Schedule 84 eligibility cap

No party expresses opposition to the Company's proposal to modify the Schedule 84 project eligibility cap to equal 100 kilowatts or 100% of the customers' demand (Staff Comments at 33, CEO at 8, City of Boise at 7 – 8, ICL at 2, Vote Solar at 49).

2. Ongoing costs of system upgrades

Staff expresses concerns that customers who install solar and storage with a combined nameplate capacity that exceeds currently applicable project caps could trigger system upgrades that result in ongoing costs (Staff Comments at 37). Staff recommends implementing a surcharge to collect ongoing operation and maintenance costs from customers who require system upgrades (Staff Comments at 36). Idaho Power's current interconnection rules already require that on-site generation customers pay for the cost of any equipment required to connect their system to the grid safely. One relatively common system upgrade encountered by customers who install solar is the need to upgrade distribution equipment like transformers. Distribution system equipment could become overloaded if combined power flows from rooftop solar exports at a given location exceed the load the equipment was originally designed to serve. Typically, this situation occurs when there are a number of nearby customers who have already installed solar, or when a customer seeks to install a relatively large solar installation in a location where minimum daytime load is low. When customers pay for the cost of a new or larger distribution transformer in order to accommodate their on-site generation project, their neighbors benefit from more capable or reliable infrastructure that they did not have to pay for, and from the deferral of the cost of replacing a transformer that would have eventually reached the end of its useful life. If a customer with on-site generation pays for a system upgrade that improves service for other customers or defers an inevitable equipment replacement, that customer should not be responsible for the ongoing costs of the upgrade they have paid for.

3. Interconnection and customer-sited storage

As discussed in Vote Solar's initial comments, interconnection rules have evolved to account for new technologies and improved availability of data. Modern interconnection rules that reflect the capabilities and flexibility of distributed energy technology available today can enable the safe interconnection of additional distributed generation in places where it could not be accommodated without system upgrades previously. In response to the update of IEEE 1547-2018, Commissions in many states have instigated dockets focused on updating state interconnection rules. It appears that Idaho Power has already implemented several best practices related to interconnection, including development of a smart inverter standard and established interconnection requirements for customers who do not plan to export energy to the grid. Additional revisions may be necessary to clarify when and how customers with storage may dispatch their batteries to the grid. At the Customer Hearing on October 24, 2023 several participants stated that there are barriers preventing them from dispatching battery storage to the grid. As summarized in Table 8 of Vote Solar's initial comments, many utilities have developed programs that motivate customers to install battery storage because of the substantial value that aggregated distributed storage resources can provide. As some examples, Green Mountain Power's customer-sited storage resources save all customers $3 million each year, and in summer 2022 distributed storage helped keep the lights on in California during a nine day heat wave.[12]

Interconnection standards that facilitate exports from battery storage are important to facilitate the continued growth of distributed energy resources in a manner that provides value to the grid, optimizes their benefits , and maintains safety and reliability. The Commission could initiate a proceeding focused on exploring best practices related to interconnection and developing a uniform statewide interconnection policy applicable to all utilities.

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[12] Utility Dive, "Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others," August 29, 2023. *Available at:* https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/

T&D World, "Virtual Power Plants, Real Benefits," October 11, 2023. *Available at: https://www.tdworld.com/distributed-energy-resources/article/21273076/virtual-power-plants-real-benefits*

4. ECR tariff language

IIPA states that solar energy is expected to decline in value over time and recommends including a warning in the ECR tariff that identifies the potential for the export credit to decrease substantially over time (IIPA Comments at 10). IIPA cites the decline in Idaho Power's calculated ECR energy value between 2022 and 2023. As previously discussed, this period captures exceptionally high energy prices during 2022 that have declined somewhat in 2023. Increases to the amount of solar generation resources on the grid may cause daytime energy prices to decline over time. However, there are other trends that have the potential to put upward pressure on the cost of electricity over time. For example, electrification of homes, buildings, and transportation is expected to increase the rate of load growth and create higher demand for electricity. Even if energy prices fall, utilities generally plan to procure a substantial amount of new generation and transmission infrastructure to serve increased customer demand, the costs of which could counteract lower energy prices. It is not appropriate to include predictions about unknown future costs on rate schedule tariff language. The proposed warning could also be confusing to customers, who may interpret the language as a guarantee that energy prices will fall in the future.

VI. CONCLUSION

In summary, Vote Solar recommends:

1) Informed by analysis demonstrating that the value of exported energy is comparable to, or higher than, volumetric retail rates that Idaho Power customers pay for electricity, the Commission should retain an equivalent rate for energy consumption and exports for Schedules 6 and 8, and maintain Schedule 84.

2) In the alternative, should the Commission elect to adopt a separate avoided cost-based financial credit rate for energy exported to the grid, the Commission should adopt an Export

Credit Rate ("ECR") of 10.04 cents per kilowatt-hour with the following program details:

a. The Commission should approve a flat annual average ECR as the default offering;

b. The ECR should be locked-in for individual customers with on-site generation at the rate effective at the time of the customer's application to interconnect their system for a period of at least 10 years;

c. The Commission should approve an optional time-differentiated ECR, available to customers with on-site generation at their discretion;

d. The ECR should include quantification of at minimum avoided energy costs, avoided line losses, avoided generation capacity costs, avoided distribution and transmission capacity costs, avoided fuel price risk, and environmental attributes, as described herein.

e. Customers who export energy to the grid should receive a payment for the full value of any unused financial credits remaining at the conclusion of their annual billing cycle;

f. Vote Solar recommends the ECR become effective on January 1, 2024 and that the first annual update take place on June 1, 2025.

3) In the event the Commission elects to adopt an ECR value that is lower than current volumetric retail rates, the Commission should determine a glide path for phasing in the ECR gradually.

4) The Commission should determine that customers who have applied to interconnect a solar installation on or before the date of the Commission's final order in this proceeding may remain on the rate current at the time of their application for a period of 20 years.

5) Vote Solar recommends the Commission approve Idaho Power's modified project

eligibility cap for commercial, industrial, and irrigation ("CI&I") customers;

6) Vote Solar recommends the Commission approve Idaho Power's proposed modifications to clarify that energy storage devices do not count towards capacity limits defined in the project eligibility cap;

7) The Commission should instruct Idaho Power to initiate a docket to evaluate program designs that motivate customers with on-site generation and storage to discharge batteries in ways that provide value to the grid, concluding with a recommendation for a program applicable to Idaho Power customers.

The technical analysis of these Reply Comments is sponsored Kate Bowman, Regulatory Director, Interior West, Vote Solar

DATED: November 2, 2023.

ELAM & BURKE, P.A.

Abigail R. Germaine

CERTIFICATE OF SERVICE

I HEREBY certify that I have on this 2nd day of November, 2023, I served the foregoing to Idaho Power Company by electronic mail to the following:

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