Office of the Secretary
Service Date
September 30, 2025

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR ITS FIRST ANNUAL UPDATE TO THE EXPORT CREDIT RATE FOR NON-LEGACY ON-SITE GENERATION CUSTOMERS FROM JUNE 1, 2025 THROUGH MAY 31, 2026, IN COMPLIANCE WITH ORDER NO. 36048	)	**CASE NO. IPC-E-25-15** **ORDER NO. 36785**

On April 1, 2025, Idaho Power Company ("Company") applied to the Idaho Public Utilities Commission ("Commission") to update the Export Credit Rate ("ECR") for non-legacy on-site generation customers from June 1, 2025 through May 31, 2026, and to approve the Company's corresponding proposed changes to Schedule 6, Residential Service On-Site Generation ("Schedule 6"), Schedule 8, Small General Service On-Site Generation ("Schedule 8"), and Schedule 84, Large General, Large Power, and Irrigation On-Site Generation Service ("Schedule 84").

On April 21, 2025, the Commission issued a Notice of Application, Notice of Suspension of Proposed Effective Date, Notice of Public Workshop, Notice of Customer Hearing, and Notice of Modified Procedure, establishing a May 15, 2025, deadline for public and Commission Staff ("Staff") comments, and a May 22, 2025, deadline for the Company to file reply comments. Order No. 36558.

The Commission granted intervention to: Kevin Dickey ("Dickey"); Clean Energy Opportunities for Idaho ("CEO"); Scott Pinizzotto ("Pinizzotto"); Sierra Club & Vote Solar ("Sierra"); Martha Bibb ("Bibb"); and the city of Boise City ("Boise City"). Order Nos. 36562; 36588; 36601.

On May 7, 2025, Staff held an in-person and telephonic public workshop in Boise, Idaho. On May 20, 2025, the Commission held an in-person and telephonic customer hearing in Boise, Idaho. Approximately 45 customers testified at the hearing.

Based on our review of the record, the Commission now issues this Final Order acknowledging that the Company's filing complied with the Commission-approved annual ECR update method outlined in Order No. 36048, suspending the annual update portion of Order No.

36048 for a period of three years, authorizing the Company to implement the updated ECR for non-legacy on-site generation customers as modified by this Order, and acknowledging the Company's consolidation of the Distributed Energy Resources ("DER") status report into the annual ECR as modified by this Order.

BACKGROUND

In 2021, the Company requested the Commission initiate a multi-phase process for a comprehensive study of the costs and benefits of on-site customer generation in anticipation of requesting potential changes to the net-metering rate design, compensation structure, or ECR. Case No. IPC-E-21-21. The Commission found it fair, just, and reasonable to direct the Company to complete a study in 2022, prior to implementing any changes to its net-metering program, using parameters specifically defined and explained by the Commission. Order No. 35284 at 9. In setting the parameters of the study, the Commission considered several iterations of comments provided by the Company, numerous intervenors, and the public. *Id.*

In 2022, the Company filed the Value of Distributed Energy Resources ("VODER") study and requested the Commission complete the review phase of the study of the costs and benefits of on-site customer generation by establishing a formal process and timeline for Staff, intervenors, and the public to review and comment on the VODER study. Case No. IPC-E-22-22. In its review, the Commission found the Company sufficiently completed the study design phase for the VODER study and that the VODER study was completed in accordance with the Commission's directives outlined in Order No. 35284. Order No. 35631 at 27.

In 2023, the Company requested the Commission authorize real time net billing with an avoided cost-based financial credit rate for exported energy, a methodology for determining annual updates to the ECR, and other administrative modifications to the Company's on-site and self-generation tariffs. Case No. IPC-E-23-14. The matter garnered significant public comments, numerous proposals and feedback from intervening parties, and sustained Company involvement, all of which the Commission thoroughly considered before issuing its Final Order. Order No. 36048.

In Order No. 36048, the Commission approved the Company's request to implement a real-time net billing ECR, as modified and refined from the original application to incorporate changes proposed by the Company and requirements outlined in the Commission's Final Order, which was informed by a thorough review of the full case record, including party proposals and public comments. *Id.* at 6. The Commission approved a seasonal and time variant methodology for determining the ECR, which included a detailed framework and annual updates to major data inputs, including: the avoided energy value; avoided generation capacity; avoided transmission and distribution capacity; avoided line losses; and integration rates. *Id.* at 6-7. The Commission directed the Company to update all components of the ECR except for the seasons and hours of highest risk in an annual filing beginning April 1, 2025. *Id.* at 7.

THE APPLICATION

The Company applied for authority to implement the updated ECR for non-legacy on-site generation customers from June 1, 2025, through May 31, 2026, and approval of its corresponding proposed changes to Schedules 6, 8, and 84. Application at 1-2. The Company asserted that the proposed updates complied with the method outlined in Commission Order No. 36048. *Id.* at 1.

As of December 31, 2024, the Company reported a total of 13,825 active and pending non-legacy Exporting Systems in its Idaho jurisdiction.[1] *Id.* at 13. The Company explained its retail customers who installed their own electricity-generating equipment, generated their own electricity, and sought to interconnect Exporting Systems were billed under Schedule 6, Schedule 8, or Schedule 84. *Id.* at 2.

The Company proposed an updated ECR for non-legacy on-site generation Schedule 6, 8, and 84 customers of 14.0598 cents per kilowatt-hour ("¢/kWh") for summer on-peak hours, 1.7682 ¢/kWh for summer-off peak hours, and 0.9540 ¢/kWh for all hours during the non-summer season. *Id.*

Additionally, the Company requested Commission authorization to consolidate its annual filings and submit its annual DER status report concurrently with its annual ECR update. *Id.* at 2. The Company believed that submitting both reports together would increase transparency for the Commission, Staff, customers, and other stakeholders. *Id.* at 15.

[1] "Exporting System" is defined in the Company's approved tariffs as "a Customer-owned DER under the terms of Schedules 6, 8, or 84, which is designed to provide for the transfer of electric energy to the Company. An Exporting System is interconnected to the Company's system under the applicable terms of Schedule 68." Schedule No. 6, at pg.6-2 (effective January 1, 2024).

PUBLIC COMMENTS

As of May 15, 2025, a total of 850[2] public comments had been filed in this case. Of those, 751 individuals (88%[3]) expressed opposition to the proposed changes to the ECR. Additionally, 364 commentors (43%) identified themselves as non-legacy customers. Some individuals raised concerns about grandfathering, with 53 commenters (6%) stating that current non-legacy customers should be granted legacy status.

Previous Orders/Studies

A total of 40 individuals (5%) questioned the validity of the VODER study, while 42 individuals (5%) recommended the Commission either review the current study or conduct additional studies. Further, 221 individuals (26%) urged the Commission to consider the environmental benefits of solar generation.

Compensation and Economics

Regarding compensation, 61 commenters (7%) expressed a preference for monthly net metering (1:1) over real time metering.

Regarding billing impacts, 108 individuals (13%) reported higher overall monthly energy costs as solar customers—citing the cost of installed systems combined with the proposed reduction in the ECR. Additionally, 139 individuals (16%) highlighted the significant financial investment they had made in installing net generation systems.

Concerns were also raised regarding fixed charges: 187 commenters (22%) opposed recent increases in the monthly service charge, while 184 individuals (22%) cited the cumulative effect of multiple rate increases within a short timeframe. Another 186 individuals (22%) stated they had no alternative provider options and believed the Company operated as a monopoly.

A total of 301 individuals (37%) stated that the compensation rate was unfair. These commenters asserted that, while customers paid the full retail rate for electricity, they were not compensated at the same rate for electricity exported to the grid. Several commenters believed the Company profited by purchasing excess electricity at a lower rate and reselling it at a higher retail rate.

[2] An additional 63 public comments were submitted after the May 15, 2025, public comment deadline established in Order No. 36558. These late-filed comments were similar in content with the timely filed comments.
[3] All percentages were calculated based on the public comments submitted as of the May 15, 2025, public comment deadline.

Installers and Annual ECR

Many individuals stated they had not been informed that the ECR would be subject to annual adjustments. Commenters also reported that they were unaware of potential program changes at the time they purchased and installed their systems. Several noted that they would not have proceeded with installation had they known the compensation rates could change.

Company Compensation

A total of 274 individuals (33%) expressed concerns about high Company profits, citing what they perceived as excessive executive compensation and board member pay. Commenters frequently used terms such as "greed" and "unfair compensation."

Disincentives

Comments from 309 individuals (36%) felt the Company was penalizing or discouraging customers from generating clean energy, despite having previously promoted solar adoption and encouraged customers to "go green."

PARTY COMMENTS

A. Staff Comments

Staff Analysis

Staff reviewed the Company's Application, the proposed tariff revisions, and the associated inputs to the ECR calculation. Staff Comments at 3. Based on its review, Staff believed the Company's Application complied with Order No. 36048. *Id.*

However, Staff identified several concerns related to the Company's 2024 Variable Energy Resource ("VER") study. *Id.* at 5. Staff recommended that the Commission adopt the current integration cost value of 0.293¢/kWh for this filing, rather than the increased value of 0.697¢/kWh derived from the 2024 VER study. *Id.* Staff also recommended in Case No. IPC-E-25-07 that the Company undertake a new VER study within six months following the filing of the 2025 Integrated Resource Plan ("IRP"). *Id.* Staff believed this timeline would allow sufficient opportunity for the Company and Staff to reconcile outstanding issues and ensure integration costs used in the 2026 ECR update are accurate and reliable. *Id.*

Staff stated that the updated ECR as proposed by the Company, would result in a significant increase to the bills of on-site generators under Schedules 6, 8, and 84. *Id.* at 6. Staff believed that the on-site generation classes (Schedules 6, 8, 84) have faced numerous increases in their monthly bills over the past 18 months. *Id.* at 6. Staff stated that although billing increases existed for all three classes, Staff focused its analysis on Schedule 6 which applies to the majority of on-site generation customers. *Id.*

Under the proposed ECR, Staff believed the average monthly bill for a Schedule 6 customer would increase from $62.35 to $83.62, representing an average increase of approximately 34%. *Id.* However, the impact would not be uniform across the class. *Id.* at 6-7. Staff's analysis indicated that customers who import the least electricity from the utility (and therefore export the most) could see bill increases of approximately 60%, while customers who import the most (and export the least) would experience increases closer to 17%. *Id.* at 7.

Staff noted that Schedule 6 customers already experienced an average rate increase of approximately 24% when the transition from net metering (1:1) to net billing (ECR) was implemented on January 1, 2024. *Id.* When combined with the proposed ECR updates, the average Schedule 6 customer could face a cumulative rate increase of approximately 67% over an 18-month period. *Id.* For customers who are high net exporters, the combined increase may exceed 100%. *Id.*

In addition to these ECR-related impacts, Staff stated that two general base rate increases were approved and implemented during the same 18-month period: one in Case No. IPC-E-23-11, effective January 1, 2024, and a second in Case No. IPC-E-24-07, effective January 1, 2025. *Id.* at 8.

<u>Mitigation Proposal</u>

To mitigate the substantial increase in customer bills resulting from the proposed ECR revisions, Staff proposed implementing a cap on the year-to-year change in the ECR. *Id.* Staff believed that this mitigation measure would help reduce annual fluctuations in the ECR and promote greater bill stability for on-site generation customers. *Id.*

Staff reasoned that rate stability was a critical regulatory objective intended to shield customers from rate shock. *Id.* To achieve this, Staff suggested that the cap include both a ceiling and a floor to limit the extent of annual changes in the ECR—both increase and decreases. *Id.* at 9. Staff proposed that the Commission apply this capping mechanism to the ECR, with the understanding that it must be tailored to the specific methodology used in calculating the ECR. *Id.*

Staff noted that the ECR consisted of two components: (1) the value of avoided energy costs and (2) the value of avoided capacity costs. *Id.* Staff proposed that the capping mechanism be applied solely to the avoided energy value component for four primary reasons: (1) Staff believed that the avoided energy value was the most significant driver of the ECR and influenced all its fluctuations, including the summer and non-summer rates, as well as the on-peak rates; (2) Staff noted that the avoided energy value, which was based on market prices derived from one year of historical data, was likely to exhibit significant year-to-year volatility due to external factors such as weather conditions, hydroelectric availability, natural gas supply and pricing, and changes in system load; (3) Staff asserted that the avoided capacity value applied only during a limited number of critical hours in the summer and only affected on-peak exports and as such, applying a cap to the capacity component would have a negligible financial impact on most on-site generation customers and could reduce the incentive for those customers to export during capacity-critical periods; and 4) Staff believed the calculation for the avoided cost of capacity already contained some level of mitigation in the five-year rolling average of historical Effective Load Carrying Capacity ("ELCC") values. *Id.*

Based on this reasoning, Staff proposed limiting the year-over-year change in the ECR energy value to no more than 30%—either upward or downward—relative to the current ECR energy value. *Id.* Staff proposed this cap be applied separately to the Summer and Non-Summer energy values. *Id.* at 10. To support this recommendation, Staff provided Table No. 4, which presented a comparative analysis of this year's ECR under various capping scenarios, specifically showing the impacts of 20%, 30%, and 40% caps. *Id.*

Table No. 4 – Alternative ECRs if Cap is Applied

Export Credit Rate by Component (cents/kWh)	Max Change	current	proposed	20%	30%	40%
Energy	Summer	5.6533 ¢	1.7682 ¢	4.5226 ¢	3.9573 ¢	3.3920 ¢
Including integration and losses	Non-Summer	4.8365 ¢	0.9540 ¢	3.8692 ¢	3.3856 ¢	2.9019 ¢
	*Annual**	*5.1566 ¢*	*1.2852 ¢*	*4.1350 ¢*	*3.6181 ¢*	*3.1013 ¢*
Generation Capacity	On-Peak	11.5862 ¢	11.9017 ¢	11.9017 ¢	11.9017 ¢	11.9017 ¢
	Off-Peak	0.0000 ¢	0.0000 ¢	0.0000 ¢	0.0000 ¢	0.0000 ¢
	*Annual**	*0.7871 ¢*	*1.1360 ¢*	*1.1360 ¢*	*1.1360 ¢*	*1.1360 ¢*
Transmission & Distribution Capacity	On-Peak	0.2456 ¢	0.3899 ¢	0.3899 ¢	0.3899 ¢	0.3899 ¢
	Off-Peak	0.0000 ¢	0.0000 ¢	0.0000 ¢	0.0000 ¢	0.0000 ¢
	*Annual**	*0.0167 ¢*	*0.0372 ¢*	*0.0372 ¢*	*0.0372 ¢*	*0.0372 ¢*
Total	**Summer On-Peak**	**17.4850 ¢**	**14.0598 ¢**	**16.8142 ¢**	**16.2489 ¢**	**15.6836 ¢**
	Summer Off-Peak	**5.6533 ¢**	**1.7682 ¢**	**4.5226 ¢**	**3.9573 ¢**	**3.3920 ¢**
	Non-Summer	**4.8365 ¢**	**0.9540 ¢**	**3.8692 ¢**	**3.3856 ¢**	**2.9019 ¢**
	*Annual**	*5.9603 ¢*	*2.4585 ¢*	*5.3083 ¢*	*4.7914 ¢*	*4.2745 ¢*

Id.

Staff also provided Table No. 5, with an estimated average monthly bill increase (for Schedule 6 customers) if the energy caps of 20, 30, or 40% were applied. *Id.*

Table No. 5 – Average Billing Impact (Schedule 6)

Export Credit Rate by Component (cents/kWh)	Max Change	current	proposed	20%	30%	40%
Monthly Bill Increase (from current ECR)			34.1%	8.6%	13.3%	17.9%

Id. Staff believed an average monthly bill increase of approximately 13% was reasonable and recommended a 30% year-to-year change limit. *Id.*

Staff acknowledged that if the Commission adopted the proposed 30% cap on year-over-year changes to the ECR avoided energy cost value, customers who consumed energy from the system would pay either more or less than the actual avoided cost for exported energy. *Id.* The outcome would depend on whether the mitigated energy value included in the ECR was higher or lower than the true avoided cost. *Id.* As a result, Staff noted that customers would no longer be indifferent between receiving energy from on-site generators who export to the grid and receiving energy from the Company's own system resources. *Id.* Staff estimated that its proposed mitigation approach would increase total ECR-related credits by approximately $4 to $5 million over the coming year. *Id.* at 11.

Staff further recommended that the ECR percentage cap remain in place on a permanent basis, regardless of whether the avoided energy value increased or decreased in future years. *Id.* Staff believed the cap would smooth out large energy price swings. *Id.* Staff believed the cap would serve to buffer customers from significant swings in market-based avoided energy prices, thereby enhancing rate stability. *Id.* Staff also observed that, if the weighted average energy price remained relatively constant over multiple years, the ECR value—despite being capped—would eventually converge with the uncapped or unmitigated avoided cost value within approximately two years. *Id.*

B. Boise City Comments

Boise City stated that it had a direct interest in the Company's approach to compensation for solar on-site generation, as the proposed changes to the ECR would materially impact the city's municipal utility billing. Boise City Comments at 1. Boise City stated it manages multiple rooftop solar accounts, which generated 109,494 kilowatt-hours ("kWh") in 2024. *Id.* Boise City stated it represents, through its constituents, nearly 139,000 customers (residential as well as commercial/industrial) as of 2024. *Id.* at 2. Accordingly, Boise City emphasized its responsibility to ensure that rates remain not only fair but also affordable for its citizens. *Id.*

Boise City stated that it had adopted a Climate Action Roadmap setting a goal of carbon neutrality by 2050. *Id.* That roadmap included specific targets to increase energy efficiency, reduce greenhouse gas emissions, and promote the deployment of clean energy—particularly rooftop solar—on both municipal and community buildings. *Id.* Boise City asserted that lowering ECR rates, even on a temporary basis, would disincentivize further investments in rooftop solar and extend the payback period for those who had already made such investments. *Id.*

Boise City agreed with the Commission's established position that the fundamental purpose of on-site generation is to offset a customer's own usage; that on-site generation should not result in cost shifting between generators and non-generators; and that customers who generate on-site should receive a fair value for their exports. *Id.* at 2 (*citing* Order No. 36048). However, Boise City raised concerns that the current ECR update proposal lacked clarity in how "fair value" was defined and calculated. *Id.*

Boise City stated that the proposed ECR rates were lower than the avoided cost rate under the Public Utility Regulatory Policies Act of 1978. *Id.* Boise City expressed concern that although the Company's proposal may comply with cost-of-service principles, the resulting rates could still be unfair and misaligned with long-term affordability and risk mitigation goals. *Id.* Boise City urged the Commission to evaluate the proposed ECR holistically and in the context of the significant demand growth the Company anticipates over the next 20 years. *Id.* at 3.

Boise City believed that customers who installed rooftop solar systems under the current (non-legacy) rate structure would face financial uncertainty under the proposed ECR. *Id.* Boise City warned that extended payback periods could reduce the incentive for future solar investments. *Id.* Boise City referenced data indicating that Schedule 6 customers could face an average monthly bill increase of 71%, while an average residential customer using 900 kWh per month could experience a 37-57% increase and argued that lowering the ECR under these conditions would run counter to principles of affordability and fairness, particularly for customers who lack the resources to invest in battery storage. *Id.*

In support of a more comprehensive approach, Boise City pointed to its prior recommendation in Case No. IPC-E-22-22 that the Company incorporate fuel price risk—especially for natural gas and coal-fired generation—into avoided cost of energy calculations. *Id.* at 4-5. Boise City stated that the current ECR methodology failed to reflect such fuel cost risk, a shortcoming it viewed as inconsistent with least-cost, least-risk planning principles. *Id.* at 5. Boise

City believed omitting fuel cost risk is inconsistent with least-cost, least-risk planning principles and underrepresents the long-term value of customer-generated solar and argued that excluding fuel risk undervalued the long-term contribution of customer-sited solar and recommended that the Commission direct the Company to explicitly include this consideration in future ECR filings. *Id.*

Boise City further asserted that the Commission had the authority and the obligation to ensure rate structures align with fair, forward-looking energy policy and contended that the Commission was not bound by prior decisions where those decisions conflicted with evolving policy objectives. *Id.* Boise City believed the Commission has broad authority to set rates that are fair, just, and reasonable, emphasizing that while cost-of-service principles could serve as a useful guideline, strict adherence to a rigid class cost-of-service methodology was neither required nor always appropriate. *Id.*

Finally, Boise City cautioned that unless the Commission intended to review each ECR calculation individually, the ECR would remain one possible outcome among many, heavily influenced by input assumptions. *Id.* Boise City suggested that the Commission reserve the ability to make post-facto adjustments to ECR values to ensure rooftop solar remains a viable means for customers to offset their consumption and receive fair value for excess energy exported to the grid. *Id.* at 6.

C. Clean Energy Opportunities for Idaho Comments

CEO expressed several concerns regarding the Company's proposed ECR update and the method used in the VER and VODER studies. CEO Comments at 1. CEO challenged the Company's assertion—based on its VER study—that utility-scale solar generation profiles were a reasonable proxy for on-site solar generation. *Id.* at 2. CEO argued that the export patterns from customers with behind-the-meter self-generation differed significantly from utility-scale generation in terms of quantity, timing, and output variability. *Id.* As such, CEO contended that increasing integration costs for on-site generators without conducting a separate evaluation specific to distributed generation was inappropriate and inequitable. *Id.* at 3.

CEO also objected to the Company's reliance on forecasted market prices in the VODER study. *Id.* at 4. CEO maintained that the use of a single year of forecasted prices introduced instability in the energy value calculation. *Id.* Instead, CEO recommended adopting a rolling average of export-weighted market prices over multiple years, which it believed would reduce volatility without sacrificing accuracy. *Id.*

CEO raised concerns regarding the treatment of negative market prices in the energy component of the ECR. *Id.* Specifically, CEO noted that when market prices were negative, the Company appeared to assume an incurred cost equivalent to the negative price, thereby reducing the average ECR for customers. *Id.* CEO argued this approach was flawed, asserting that market prices should reflect the opportunity cost of energy the Company would otherwise need to generate or procure—not the cost to receive exported energy from customers. *Id.* at 5.

CEO also identified a misalignment between the price signals sent for energy consumption and those sent for energy exports. *Id.* at 6. This disconnect, CEO argued, imposed undue financial harm on customers, particularly Idaho farmers, who rely on predictable pricing signals for operational planning. *Id.* CEO believed customers should not be penalized due to delays in aligning consumption rates with hourly cost causation for both energy and capacity. *Id.*

Regarding rate design, CEO cautioned that any proposed reduction in the non-summer ECR exceeding 50% would be unreasonable and inconsistent with the regulatory principle of gradualism. *Id.* at 7. CEO urged the Commission to ensure that rate changes proceed in a measured, incremental manner to avoid customer disruption and support long-term investment in distributed energy resources. *Id.*

D. Kevin Dickey Comments

Dickey asserted that the Commission had allowed the Company to unilaterally determine the ECR and that the resulting policy was neither fair, just, nor reasonable. Dickey Comments at 2. He believed the Company had a vested interest in maintaining a low ECR and faced a conflict of interest in setting the rate. *Id.*

Dickey further contended that the Company supplied renewable energy to the grid through its partnership with Micron, and that this renewable energy directly competed with Idaho's small-capacity generators. *Id.* He cited recent blackouts in Spain as evidence that electrical systems have a threshold for safely integrating renewable energy. *Id.* According to Dickey, the Company promoted a low ECR to discourage small generator capacity, thereby preserving grid access for its large generator partners to dominate the renewable energy market. *Id.*

Dickey maintained that the Company was conflicted when it presented the VODER study to establish the ECR and argued that the Commission had permitted a conflicted party to determine the method for setting the ECR. *Id.* at 4. He believed that a third-party study would have provided a more appropriate and impartial basis for determining the ECR. *Id.*

Dickey claimed that the use of negative values in the 2024 energy value calculations demonstrated the Company's manipulation of the ECR in its favor. *Id.* at 5. He argued that the Company's objections to his production requests effectively acknowledged that the pricing used in the Energy Value portion of the VODER calculation was unrealistic and had been intentionally selected to minimize the resulting ECR. *Id.*

Dickey concluded that the Company should be excluded from any future role in determining the ECR and that an independent third party should be retained to help establish a fair, just, and reasonable outcome. *Id.* at 6. He further asserted that "whoever determined that the Legacy 1:1 system of remuneration needed to be replaced" and should bear the cost of such third-party assistance. *Id.* Lastly, Dickey alleged that the Company had used funds saved by reducing payouts to small generators to pay executive bonuses and argued that the Company should fund an independent evaluation to prove that the Legacy 1:1 program was unfair. *Id.*

E. Martha Bibb Comments

Bibb stated that in 2021, the Commission directed the Company to quantify the environmental and health benefits associated with solar power. Bibb Comments at 1. Bibb asserted the Company's VODER study concluded that the quantified value of these benefits was 0 ¢/kWh. *Id.* at 2. In contrast, Bibb noted that the Crossborder[4] study determined the value of environmental and health benefits from solar power to be between 3 ¢ and 11.7 ¢/kWh. *Id.* Based on this disparity, Bibb urged the Commission to reassess the Company's assumptions regarding the value of solar to environmental and public health. *Id.* She believed that such a reassessment would align with the Commission's mission to promote general safety, health, and public welfare. *Id.*

Bibb asserted that solar power displaces fossil fuel-based generation and helps mitigate climate change, resulting in tangible health benefits and lower health-related costs for both ratepayers and society at large. *Id.* at 3. She maintained that the Commission had a moral and public duty to account for the value of health-related cost savings in its decision-making. *Id.*

[4] In Case No. IPC-E-22-22, intervenor Idaho Conservation League co-commissioned the Crossborder Energy ("Crossborder") study to review and assess the Company's VODER study and ultimately believed the VODER study undervalued distributed generation.

Bibb further argued that solar energy reduces the Company's exposure to expenses related to fossil fuel use and climate change, which could ultimately affect rates and ratepayers. *Id.* She believed that the Company could leverage solar generation to avoid future costs such as carbon taxes and indemnity bonds. *Id.* Bibb encouraged the Commission to revisit the Crossborder study, which she claimed quantified avoided carbon costs. *Id.*

Bibb also stated that distributed solar helps mitigate the climate-related impacts on hydropower generation and that these avoided costs should be reflected in the ECR calculations. *Id.* at 4. She contended that the ECR should also account for avoided costs related to the reduction of climate-driven natural disasters, which she attributed in part to the deployment of distributed solar. *Id.*

Additionally, Bibb argued that solar generation reduces reliance on "distant, dirty power generation," thereby decreasing the Company's line losses, increasing grid resilience, and reducing the need to build new methane gas plants. *Id.* She asserted that distributed solar lessens dependence on long-distance transmission from centralized sources, which in turn decreases community vulnerability during power outages. *Id.*

Bibb concluded by requesting that the Commission review the ECR methodology to ensure it reflects the "full and true value that ratepayers receive, including any climate and environmental benefits that ultimately tie back to system costs and customer rates." *Id.*

F. Scott Pinizzotto Comments

Pinizzotto stated that he was a solar homeowner who generated 21 megawatt-hours of solar energy in 2024. Pinizzotto Comments at 1. He explained that for eight to nine months of the year, his solar system produced more energy than his household consumed on a daily basis, resulting in excess power being supplied to the grid. *Id.*

Pinizzotto expressed concern that the proposed ECR would be unfair to customers and would disproportionately benefit the Company by allowing an excessive margin of profitability. *Id.* He opposed the concept of varying the ECR throughout the day and argued that the rate the Company pays for customer-supplied power should match the rate customers pay for energy consumed from the Company. *Id.* at 2.

Pinizzotto further contended that the current methodology, as approved by the Commission, did not prioritize fairness for customers. *Id.* Instead, he believed it enabled the Company to achieve an excessive profit margin and failed to directly address the fixed costs associated with maintaining and distributing the infrastructure necessary for grid interconnection. *Id.* at 3.

G. Sierra Club & Vote Solar Comments

Sierra stated that it believed the Company's Application contained errors and omissions that undervalued solar exports from on-site generation customers, and that the existing record was insufficient to determine whether the proposed ECR was accurate or appropriate. Sierra Comments at 7. Sierra asserted that the proposed ECR would result in rate shock for on-site generation customers and recommended that the Commission implement gradualism to mitigate sudden and dramatic changes. *Id.*

Sierra noted that the proposed update would result in a 70-80% reduction in the avoided energy cost component of the ECR compared to the current rate. *Id.* at 8. Sierra expressed concern that basing the ECR on only 12 months of historical Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") prices would expose on-site generation customers to unacceptable levels of financial risk and uncertainty—risks that would not be acceptable to other generation resource owners. *Id.* Sierra argued that such volatility would make it difficult for customers to assess the financial viability of investing in on-site generation. *Id.* at 8-9. To improve ECR stability, Sierra recommended that avoided energy costs be calculated using a 36-month average of ELAP market prices from January 2022 through December 2024. *Id.* at 9. Sierra further recommended that the Commission direct the Company to revise its Application using this 36-month ELAP market price average. *Id.*

Sierra also raised concerns regarding the VER study, which quantifies the cost of ancillary services needed to integrate solar into the grid. *Id.* at 9-10. Sierra argued that increased battery deployment should lower, not raise, integration costs. *Id.* at 10. Sierra further contended that using a utility-scale solar generation profile to estimate integration costs for distributed on-site solar generation was inaccurate and inappropriate; instead, the actual export profile of on-site generation should be used. *Id.* at 12. Sierra urged the Commission to reject the Company's proposed integration cost. *Id.*

Sierra also questioned the ELCC values the Company used in its calculations, citing concerns about the continued use of a methodology that stakeholders and regulators could neither review nor verify. *Id.* at 12-13. Sierra argued that on-site generation customers should be compensated for updated ELCC calculations from 2020, 2021, and 2022, and claimed that the use of an incorrect ELCC average resulted in an underpayment of 1.503 ¢/kWh. *Id.* As a remedy, Sierra recommended the Commission direct the Company to issue a one-time bill credit to each on-site generation customer based on the energy exported during summer on-peak hours from January 1, 2024, until the updated ECR is implemented. *Id.*

Sierra contended that the ELCC methodology produced unexpected and volatile results, despite the predictable daily and seasonal patterns of on-site solar output. *Id.* at 14-15. Without transparency in the ELCC calculations, Sierra stated that stakeholders could not determine whether the low 2024 value was due to actual capacity changes or a methodological error. *Id.* at 14. Sierra urged the Commission to approve a capacity contribution methodology that is both transparent and verifiable. *Id.* at 18.

Regarding avoided transmission and distribution ("T&D") costs, Sierra expressed concern that the Company's approach relied on a short-term snapshot that identified only those T&D projects that could be fully deferred by on-site generation. *Id.* at 19. Sierra argued that this standard was inconsistent with how the Company treated other generation resources and failed to capture the proportional value that on-site exports provide. *Id.* at 20. It recommended that the Commission reject the Company's proposed avoided T&D cost value of $0 and direct the Company to quantify the marginal value of avoided transmission costs due to on-site generation. *Id.* Sierra suggested that this analysis could use the National Economic Research Associates regression method, the avoided on-peak T&D capacity costs from the Company's 2023 IRP, or the Company's Open Access Transmission Tariff rate. *Id.* at 21.

Finally, Sierra recommended that the Commission direct the Company to implement a Virtual Power Plant ("VPP") program that would allow the Company to dispatch aggregated customer battery systems. *Id.* at 24. Sierra proposed that the VPP program include a capacity payment equal to the Company's cost for battery storage and stated that such a program could help meet future energy needs in a manner that is affordable, reliable, flexible, and scalable. *Id.*

COMPANY REPLY COMMENTS

Company General Reply

The Company clarified that it believed the Application did not present a new proposal, but rather, the Company filed an annual cost adjustment to the reimbursement rate for excess energy generated by on-site generators based on the Commission approved methodology established in 2023. Company Reply at 1. The Company stated it recognized the proposed inaugural update would result in varying customer bill impacts, including large bill increases, and presented a "one-time mitigation option for the Commission's consideration." *Id.* at 2.

The Company modified its request to the Commission, requesting the Commission issue an order: (1) acknowledging the Company's original Application conformed with the Commission-approved annual ECR update method outlined in Order No. 36048; (2) authorizing the Company to implement the updated ECR for non-legacy on-site generation customers effective June 1, 2025, as directed in Order No. 36048; (3) as needed, directing the Company to submit corrected tariff sheets reflecting the incorporation of any mitigation measures ordered by the Commission; and (4) acknowledging the Company's consolidation of the DER status report into the annual ECR update. *Id.* at 2.

The Company stated its Application was initiated in compliance with Commission Order No. 36048 issued in Case No. IPC-E-23-14. *Id.* at 3. The Company stated the Order approved changes to its on-site generation service offerings including implementing, effective January 1, 2024, a seasonal and time-variant ECR with avoided cost-based value considerations for excess energy exported to the Company's system by non-legacy customers as well as approving a method to determine annual updates to the ECR. *Id.* The Company stated that in authorizing changes to the Company's on-site generation offering, the Commission emphasized that the fundamental purpose of on-site generation is to offset a customer's own usage, that on-site generation should not create cost shifting between generators and non-generators, and that on-site generators should be given a fair value for their exported energy. *Id.*

The Company stated the method approved in Order No. 36048 in Case No. IPC-E-23-14 was informed and refined by feedback from Staff and the parties in that case, including many of the same parties who intervened in the current docket. *Id.* at 4. The Company stated the Commission-approved method adopted in Order No. 36048 incorporated elements of the Company's proposal in addition to proposed modifications recommended by Staff and the other parties. *Id.* The Company stated it filed its first annual update of the ECR for non-legacy on-site generation customers from June 1, 2025, through May 31, 2026, in compliance with the methods prescribed by the Commission in Order No. 36048. *Id.* at 4-5. The Company believed no party had taken the position that the Company's update failed to follow the Commission's direction from Order No. 36048. *Id.* at 12. The Company suggested many commentors were unaware that the ECR update proposed in this docket was an annual update based on the methodology that the

Company believed to be "previously vetted, informed, and refined through a collaborative and iterative process that represented the culmination of a multi-year effort to have the Commission review and modify outdated net metering offerings to better align with the actual circumstances." *Id.* at 5.

The Company stated that many of the comments overlooked the regulatory precedent and that many of the issues raised were already addressed by the Commission or were otherwise outside the scope of a compliance filing docket. *Id.* at 8-9. The Company reasoned that even though many of the comments disagreed with the ECR methodology previously adopted by Order No. 36048, it was not appropriate for parties to now challenge the approved methods for calculating the ECR components, or to seek to deviate from the annual update process directed by the Commission. *Id.* at 9. The Company believed such challenges represent an impermissible collateral attack on Order No. 36048, a violation of *Idaho Code* § 62-625, which provides: "[a]ll orders and decisions of the commission which have become final and conclusive shall not be attacked collaterally." *Id.* at 9-10. The Company stated *Idaho Code* §§ 62-626 and 61-624 direct that Final Orders of the Commission should be challenged either by petition to the Commission or appeal to the Idaho Supreme Court. *Id.* at 10. The Company believed the parties had not demonstrated that, in the 18 months since the Commission issued its decision authorizing the ECR methodology, conditions have changed such that the method needs to be re-evaluated. *Id.* at 10-11.

The Company believed many commentors misunderstood the role of the ECR, and the Company emphasized previous Commission Orders where the Commission has stated the purpose of establishing rates "is not to ensure that customers who have installed self-generation facilities are able to recoup their investment or earn a return on investment, it is to ensure that customers are paid fair, just, and reasonable rates for their exports and non-self-generating customers are not subsidizing the rates for self-generating customers." *Id.* at 11 (quoting Order No. 35631).

The Company stated it did not address recommendations and considerations set forth in the comments that were outside of the scope of these proceedings including proposals calling for alternative compensation structure, modifications to the ECR methodology, or that otherwise sought to relitigate issues that were already decided in a prior case. *Id.* at 12.

<u>Company Reply to Components of the ECR</u>

A. Avoided Energy Costs

i. Energy and Avoided Line Losses

The Company rejected all recommendations and maintained that using actual historical ELAP prices, weighted for customer exports, was an appropriate method for valuing the non-firm energy provided by customer on-site generators as the Company believed it achieved timely recognition of changing conditions on the Company's system and the broader power markets. *Id.* at 14. The Company believed including negative ELAP market prices in the hours they may occur when determining each year's ECR was appropriate and necessary to keep non-participating customers indifferent. *Id.* at 16.

ii. Integration Costs

The Company found Staff's position that proposed integration costs are under-allocated through the ECR contrary to CEO and Sierra, which both took the position the integration costs proposed were too high. *Id.* at 18. The Company stated relying on the proposed integration charge in this case reasonably assigns a portion of the costs associated with integration to on-site generation exports. *Id.* at 19. The Company stated that to the extent future VER studies identify methods to adjust for the under-allocation issue Staff raised, those results will impact future ECR updates. *Id.* The Company stated it has agreed, in Case No. IPC-E-25-07, to work with Staff to address the issues raised in Staff's comments, which include several aspects expected to impact the integration costs assigned to the ECR in future updates. *Id.*

B. Avoided Generation Capacity

The Company disagreed with comments that claimed the ELCC is non-transparent or an un-verifiable method. *Id.* at 20. The Company disagreed with claims about data manipulation to exclude off-peak exports and believed the ELCC calculation incorporated all hours of the year, including on-peak and off-peak exports, as adopted by the Commission in Order No. 36048. *Id.* at 20-21. The Company disagreed that the model did not account for the impact of avoided line losses because line losses were not part of the ELCC calculation. *Id.* Line losses were accounted for after the ELCC calculation was performed, as directed by Order No. 36048. *Id.*

The Company believed that Sierra overstated the significance of the proposed adjustments to the ELCC values for 2021 and 2022 in the ECR update because the Company updated its calculation of the ELCC for customer generator exports to reflect that the resource originates behind-the-meter. *Id.* at 23. The Company disagreed that it was appropriate or necessary to issue a bill credit to customers to account for a corrected ELCC. *Id.* The Company reasoned the proposal to apply a credit to customers based on a rate different than the Commission-approved tariff would violate the filed-rate doctrine, codified in *Idaho Code* § 61-313, and was therefore not inappropriate. *Id.*

C. Transmission and Distribution Capacity

The Company stated that it updated all values of the ECR, including the avoided T&D capacity component, in accordance with Order No. 36048. *Id.* at 24. The Company reasoned that the Commission had already considered several of the alternative methods presented in previous ECR cases and the Commission declined to adopt those methods. *Id.*

Company Reply to Mitigation

The Company believed that the proposed ECR rates presented in this case complied with the Commission's three primary principles that guided its decision in Order No. 36048: (1) the fundamental purpose of on-site generation to offset a customer's own usage, (2) that on-site generation should not create cost shifting between generators and non-generators, and (3) on-site generators should be given a fair value to their exported energy. *Id.* at 26. The Company believed the updated rates in this case complied with all three principles because: (1) the updated ECR would have no impact to a customer's ability to generate and consume their own energy; (2) implementing the updated ECR, as proposed, would help to ensure nonparticipating customers remain indifferent to the source of their energy, whether it be from an on-site generator's exports or another Company resource; and (3) the Commission recently found the approved methodology results in a fair assignment of value to on-site generators. *Id.*

The Company did not agree with Staff's mitigation mechanism proposal, as described in Staff's comments. *Id.* at 27. The Company stated it is concerned that in a future period where market prices increase, thereby positively impacting the ECR, stakeholders would expect the ECR to reflect that value and would be highly critical of the Company employing a mitigation measure that restricted the value of exported energy from customer generators. *Id.* The Company also disagreed with Staff's assessment of how long it would take the avoided energy component to equalize to the unmitigated value under Staff's proposal. *Id.* While Staff stated that it believed the unmitigated value would equalize in two to three cycles, the Company believed the equalization would take four cycles to complete. *Id.* at 28.

The Company believed a one-time 50% change limit, as proposed by CEO, would yield a more favorable result than Staff's proposed methodology. *Id.* at 30. The Company stated that should this mitigation proposal be adopted, the application of a 50% mitigation to both the summer and non-summer avoided energy components would be appropriate, contrary to CEO's approach to only apply the mitigation to the non-summer months. *Id.*

The Company requested the Commission reject Staff's recommendation to implement an ongoing mitigation mechanism. *Id.* The Company believed an ongoing mitigation mechanism would be unnecessary and would ultimately impact the rates of non-participating customers. *Id.* at 32.

Finally, the Company requested the Commission consider the reasonableness of implementing mitigation, when the Company believed any mitigation measure implemented would inevitably perpetuate inaccurate price signals to customers. *Id.* The Company believed updating the ECR consistent with the previously established methodology would be the best way to ensure customers receive an accurate price signal to inform decision making and to ensure non-participating customers remain indifferent. *Id.*

DER Report

The Company acknowledged Sierra's suggestion that the Company make past copies of the DER report available on the Company's website, and the Company stated that it intends to continue making three years of past reports available, which the Company believed is consistent with how it maintains other Commission-required reports. *Id.* at 33. The Company also stated it intended to name the report based on the reporting year, rather than the month of submission so it is titled consistent with the reporting period. *Id.*

Public Comments

In response to customer comments regarding the impact the proposed ECR changes would have on the payback period for customers, customers' unawareness that the rates could change, and/or calls for expanded legacy treatment, the Company stated that it was not within its purview to ensure the bilateral transaction between the sellers or installers of on-site generation systems and their customers was equitable and economically supportable. *Id.* at 34-35. The Company believes it is legally obligated to consider the collective interests of all its customers and to develop mechanisms based on an economically supportable analysis that result in fair, just, and reasonable rates for customers, rather than simply as a means to achieve particular policy goals. *Id.* at 35. The

Company believed the Commission had been clear in previous orders that the Commission's objective was to ensure that customers are paid fair, just, and reasonable rates for their exports, and that non-self-generating customers are not subsidizing the rates for self-generating customers. *Id.* The Company stated its objective was not to ensure that customers who have installed self-generation facilities are able to recoup their investment in a specific period of time or earn a return on investment. *Id.*

The Company stated that the procedural schedule in Case No. IPC-E-23-14, and the series of on-site generation dockets that preceded it provided ample opportunities for comment and customer participation, and the Company believed public and party involvement had been robust and instrumental throughout the underlying process. *Id.* at 37. The Company stated it has been, and will continue to be, committed to clearly and transparently notifying potential and existing on-site generation customers that on-site generation rates and program structure are subject to change. *Id.*

The Company provided a summary of the communications it sent to its customers to notify them of the potential change to rates, information on Commission Orders, and information required to be provided by solar retailers. *Id.* at 38-40. The Company also provided the customer acknowledgement the Company requires all generation applicants to sign, acknowledging they understand the program fundamentals and that compensation for excess energy is subject to change. *Id.* at 41.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over the Company's Application and the issues in this case under Title 61 of the Idaho Code including *Idaho Code* §§ 61-301 through 303. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of all public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provisions of law, and to fix the same by order. *Idaho Code* §§ 61-501 through 503.

The Commission now considers the Company's request to update the ECR for non-legacy on-site generation customers and the Company's corresponding proposed changes to Schedules 6, 8, and 84. The Commission has examined the comprehensive record in this matter, including all comments submitted by the public, intervenors, and the Company. The Commission appreciates the robust public engagement—through both written comments and live testimony—and extends its gratitude to everyone for the thoughtful participation and valuable insights.

Issues Raised in Prior Orders

Several parties and public commenters raised concerns regarding specific components of the proposed ECR update. Sierra challenged the avoided cost of energy and integration cost components, arguing the use of 12 months of ELAP pricing was too volatile and that the integration cost methodology failed to reflect reduced costs due to increased battery deployment. Sierra also questioned the transparency and accuracy of the Company's ELCC capacity calculations and the assignment of a $0 value to avoided transmission and distribution costs. Bibb and other public commenters emphasized the failure to quantify environmental and health benefits, contrasting the Company's $0 valuation with other studies assigning significant societal benefits to these components. Public commenters also expressed concern over increased payback periods, lack of awareness about ECR variability; several requested extended legacy treatment beyond the grandfathering that was approved in Order No. 34509, in Case No. IPC-E-18-15. The Company argued that the proposed ECR update adhered to the Commission-approved method, opined that broader changes would constitute an improper collateral attack on prior Commission orders, and reiterated that its responsibility is to ensure fair and non-subsidizing rates—not to guarantee customer investment returns.

The Commission has previously and continues to maintain that "the fundamental purpose of on-site generation is to offset a customer's own usage; that on-site generation should not create cost shifting between generators and non-generators, and that on-site generators should be given a fair value for their exported energy." Order No. 36048 at 5. Additionally, in Order No. 35284, the Commission reiterated that "tariffs are not contracts and the prices and terms of service for the net-metering program are subject to change." Order No. 35284 at 10.[5] Further, the Commission stated that "[a] utility's rate schedules, including net-metering program fundamentals, are subject to change. As such, there is no guaranteed return on investment." *Id.*

In the same spirit, the Commission has emphasized the importance of efforts to notify potential customers that rates are subject to change and could affect the projected repayment period

[5] The Commission has repeatedly stated over the years that tariffs are not contracts and that prices and terms of service for the net metering program are subject to change. *See* Order No. 30227 at 7; Order No. 32280 at 4; Order No. 34046 at 19; and Order No. 34335 at 2.

of the customer's investment. Order No. 34509 at 13. The Commission noted the statutory provisions in Title 48 and stated "[a]s of October 1, 2019, the Residential Solar Energy System Disclosure Act, *Idaho Code* §§ 48-1801 - §48-1809, requires a written statement be provided to potential customers that states, in capital letters, among many other warnings, that 'LEGISLATIVE OR REGULATORY ACTION MAY AFFECT OR ELIMINATE YOUR ABILITY TO SELL OR GET CREDIT FOR ANY EXCESS POWER GENERATED BY THE SYSTEM AND MAY AFFECT THE PRICE OR VALUE OF THAT POWER.' *Idaho Code* §48-1804(c)(ii)." *Id.*

In Case No. IPC-E-23-14, the Commission directed the Company to "update all proposed components of the ECR except the season and hours of highest risk in an annual filing beginning April 1, 2025" and to submit proposed updates to the corresponding schedules reflecting the updated ECR. Order No. 36048 at 7. The Commission provided a comprehensive review of each component of the ECR calculation in its decision, seeking "to accurately assign the appropriate share of fixed costs and unquantified benefits of on-site customer generation, and to provide a reasonable balance between the interests of customers with on-site generation, and customers without." *Id.* at 6.

In formulating the ECR, the Commission considered the long history of cases dealing with on-site generation, public comments and testimony, and proposals offered by all parties. Many of the proposals and concerns offered and addressed in Case No. IPC-E-23-14 are similar in nature to the recommendations and concerns offered in this matter. As such, to the extent these proposals and concerns fall outside the scope of this proceeding, they will not be discussed further.

VER Study Concerns

Staff, CEO, and Sierra raised concerns regarding the integration rates from the VER study used in the calculation of the ECR. While the Commission acknowledges these concerns and recommendations, those issues were addressed by Order No. 3661 in Case No. IPC-E-25-07. In that case, Staff recognized the impact of the VER study on the ECR and recommended working with the Company to resolve various issues including inter-hour integration costs, differences in wind and solar integration costs, under-allocation, and incorporating on-site generation in the analysis. Order No. 36661 at 2-3. Order No. 36661 directed the Company to work with Staff prior to the next VER study and attempt to resolve Staff's outstanding concerns. *Id*. at 4. Additionally, the Commission ordered the Company to file a new VER study within six months after the filing of each IRP. *Id.*

<u>Present Issues</u>

The Commission has reviewed the Company's Application to update the ECR, along with the proposed updates to Schedules 6, 8, and 84, in accordance with the directives of Order No. 36048. Based on our review, the Commission finds the Company's filing is in conformance with the Commission-approved annual ECR update methodology outlined in Order No. 36048.

While the Company has complied with Order No. 36048, the Commission is keenly aware that all customers—including non-legacy on-site generation customers—have faced increases to their average monthly bills over the past 18 months. The Commission recognizes that the updates to the ECR proposed in the Company's Application would further affect customers in Schedule 6, 8, and 84. As demonstrated in the record, if the proposed updates to the ECR were approved as filed, some Schedule 6 customers' monthly bills would increase by up to 100% in a relatively short period (factoring in the multiple changes to the ECR compounded with the recent general rate increases).

To reduce the impact of the recent rate changes, the Commission finds that some mitigation is reasonable in the updated ECR. After considering the options presented, an ECR update where the change in the avoided energy value is limited to a 40% decrease from the current ECR's avoided energy value, applied to both the summer and non-summer months, is reasonable.

We find that the annual update to the ECR as required by Order No. 36048 is difficult for non-legacy on-site generation customers to adjust to and complicates investment decisions by potential on-site generation customers. Therefore, we have determined that suspension of the annual update requirement is appropriate for now. The annual update requirement of Order No. 36048 shall remain suspended and the mitigated ECR shall remain in effect until 2028, at which time the Company shall update all components of the ECR except the season and hours of highest risk in an annual filing by April 1, 2028, in compliance with Order No. 36048. The Company shall submit a compliance filing with Schedules 6, 8, and 84 conforming with this Order.

The Commission acknowledges and accepts the Company's decision to consolidate the DER status report into this year's annual ECR update. However, for the period the ECR is set by this Order, the Company shall annually submit the DER status report in a separate filing. When the annual ECR update resumes in 2028, the Company may once again combine the DER status report with the ECR update.

ORDER

IT IS HEREBY ORDERED that the Company's Application to update the ECR for non-legacy on-site generation customers is approved, subject to the mitigation and modifications set forth in this Order, effective October 1, 2025.

IT IS FURTHER ORDERED that the annual update requirement of Order No. 36048 is suspended until 2028.

IT IS FURTHER ORDERED that the Company shall maintain the ECR at the rates set by this Order until it is updated based on the Company's April 1, 2028, filing, which shall be in compliance with Order No. 36048.

IT IS FURTHER ORDERED that the Company shall submit, as a compliance filing, corrected tariff sheets reflecting the updated ECR as modified by the Commission decision above within 30 days of this Order.

IT IS FURTHER ORDERED that for 2026 and 2027, the Company shall file a standalone DER status report. In 2028 the Company is permitted to file its DER report with the annual ECR update.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of September 2025.

EDWARD LODGE, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

DAYN HARDIE, COMMISSIONER

ATTEST:

Laura Calderon Robles
Interim Commission Secretary

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