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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	)))))))))	**Case No. IPC-E-23-14** **Clean Energy Opportunities for Idaho** **Initial Comments**

Clean Energy Opportunities for Idaho (CEO) seeks to serve the long-term interests of Idahoans, which includes the freedom of customers to control their energy. Our comments are organized along the topics below. These include requests affecting the near-term implementation of proposed changes to the compensation structure as well as the need for related ongoing endeavors.

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Note: CEO's specific requests are flagged with a "►" .

Timing for Implementation – Classes impacted differently, Schedule 84 needs to move forward

Customer classes are impacted differently by IPC-E-23-14. Regarding the effective date of the changes proposed in this docket, we believe that timely resolution and visibility to new terms are priorities for CI&I customers, yet gradualism is a merited concern for Residents and Small General Service customers.

- **Schedules 6 & 8 – Concerns for gradualism:** For Schedules 6 & 8, the impact of IPC-E-23-14 on electric bills is outside the realm of gradualism. In addition to the change in export value, net billing affects electric bills for consumption by both changing the volume of kWh billed and, due to tiered rates, the rates at which consumption is billed. While the Company has provided notice of potential changes, notice does not substitute for gradualism in rate cases or in this docket.

- **Schedule 84 – Priority on resolution and visibility:** Unlike Schedule 6 & 8 projects, the design of CI&I projects is substantially affected by implementation of the proposed changes in IPC-E-23-14. We believe, and the public record in IPC-E-22-12 has shown, that CI&I customers have an interest in visibility to new terms and the implementation of Schedule 84 changes sooner rather than later.

Solutions are imperfect. It is challenging to implement IPC-E-23-14 in a manner that addresses gradualism for Schedule 6 & 8 customers yet does not delay CI&I customers from initiating long lead-time projects impacted by changes to Schedule 84. Other parties may put forward proposals which CEO could support, provided that such requests do not impede the implementation of non-ECR related changes to Schedule 84.

► In the event the Commission would not support proposals by other commenters concerned with gradualism, CEO suggests the following "minimalist" approach to gradualism: **Set the effective date as January 1, 2024, yet set the next update of the ECR to occur in June 2025 rather than June 2024**. For CI&I customers, this would avoid unnecessary delay in the design and evaluation of large projects impacted by Schedule 84 changes, and would provide visibility to the ECR value. These 18 months are an important time window for accessing federal funds. For Schedule 6 & 8 customers, this "minimalist" approach to implementation may not satisfy all interests in gradualism, yet this proposal would at least allow some stability for the market to move forward without the disruption of another change in ECR value in June 2024.

► In general, **CEO supports the proposed effective date of January 1, 2024 for changes to Schedule 84**. If the Commission considers delaying implementation of the ECR (e.g., to an effective date in June of 2024), CEO would request that non-ECR related changes to Schedule 84 be effective January 1, 2024 (or as soon as possible) in order not to impede the design, evaluation, application process, and installation of projects for the irrigation season. CEO believes that the freedom of customers to control energy costs and to access time-sensitive federal funds outweighs any concern that these long lead-time projects might get installed and generate substantial exports during a 6-month lag between implementing Schedule 84 design-related changes and making the new ECR in effect.

Fuel Price Hedge Value (VODER 4.1.5) – It shouldn't be set at zero

In IPC-E-21-21, the Commission ordered the evaluation of fuel price risks within the VODER study.[1] IPC-E-23-14 proposes an ECR which does not reflect an evaluation of fuel price risks, it reflects the Company's argument that there is no hedge value. The Company asserts the value is zero because exports are non-firm and often occur in midday hours, "resulting in no reduction in pricing risk during the net-peak load".[2] However, the

[1] Order 35284 at 22: "It is reasonable to evaluate fuel price risks."

Company's proposed ECR already reflects the contribution to peak and non-firm nature of exports, these arguments do not justify assigning zero value to price hedge benefits. Customer load reduction at any hour reduces the aggregate fuel the Company would either buy directly or implicitly through market purchases. The hedge value is not zero. Consider two example analyses:

E3 Recommendation: In a docket to determine the Resource Value of Solar for PacifiCorp, the PUC of Oregon ordered the value set at 5% of avoided energy, as described in ORDER NO. 19-021[3] regarding **Hedge Value:**

> For this element, we adopted the E3 suggestion for a 5 percent hedge value of avoided energy. E3 's recommendation is derived from a peer-reviewed paper entitled *How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest.* [29] We noted that "[w]e decline the suggestion for a zero value, because similar to Market Price Response, we are persuaded that there is value to this element."[30]
>
> FN29: Andre DeBenedictis, David Miller, Jack Moore, Arne Olsen, & C.K. Woo, *How Big is the Risk Premium in an Electricity Forward Price?*, 24 the Electricity Journal 72, (April 2011).
> FN30: Order No. 17-357 at 12

Rocky Mountain Power Idaho: ln Idaho, Order No. 34753 (PAC-E-19-08, Attachment A, @ p2), the Commission directed Rocky Mountain Power to "Analyze whether there is a fuel price guarantee value provided by on-site generators as a class". The utility reported in its June 2023 On-Site Generation study that there is a real and measurable value:

> "Over the 2021 IRP horizon, this increases the energy value of customer exports by 3.9 percent."[4]

In Idaho Power Response to Staff Production No. 43 regarding why the Company did not deploy this analysis, the Company states "Any market-based variability is already reflected in actual market prices, such as the ELAP price used in the Company's proposal." This argument is inadequate. With each ECR update, the Company locks in a price for customer exports which avoids risks associated with the Company's reliance on volatile fuel prices for the coming year.

The Commission's order in IPC-E-21-21 to evaluate fuel price hedge value was informed by evidence[5] and party requests, which were reiterated in IPC-E-22-22. As the PUC of Oregon concluded, there is value to this element. CEO requests -

- That the ECR should be updated to reflect that the fuel price hedge value is not zero.
- That ECR rates reflect a price risk benefit equal to 5% of avoided energy value consist with the E3 recommendation to PacifiCorp[6]. In the event the Commission does not accept this request, CEO asks at

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[2] October VODER study, p55: "Exports from customer-generators do not provide a fuel-cost hedge benefit. Customer-generator exports on Idaho Power's system occur intermittently in the midday hours when it is generally less valuable, rather than on a firm basis in the highest net-peak hours, when it would be most needed — resulting in no reduction in pricing risk during the net-peak load."

[3] Jan 22, 2019 ORDER NO. 19-021 at 20, UM 1910 Order.pdf&il=true (state.or.us)

[4] PAC-E-23-17, Rocky Mountain Power On-Site Generation Study, at 23. "PacifiCorp's 2021 IRP included stochastic analysis, which evaluated portfolio costs considering variations in load, hydro output, electricity and natural gas prices, and thermal unit forced outages. PacifiCorp's calculation of the energy value and cost-effectiveness of energy efficiency measures used these stochastic results to identify the incremental value associated with these risks, and PacifiCorp has calculated the avoided risk associated with customer exports using the same risk values applied to energy efficiency. Over the 2021 IRP horizon, this increases the energy value of customer exports by 3.9 percent, or $1.24/MWh as shown on summary tab of CONF Appendix 4.2: ID EE Cost-Effectiveness."

[5] *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*, p36, by the Interstate Renewable Energy Council, states: "A fuel price hedge value should be included." Presented in CEO's IPC-E-21-21 and IPC-E-22-22 comments.

minimum that the energy value of customer exports be increased by 3.9% to reflect a fuel price hedge value consistent with the analysis completed by Rocky Mountain Power for its Idaho on-site generation customers.[7]

Avoided Generation Capacity (VODER 4.2) – If reduced, would change non-firm adjustment

Regarding the Avoided Generation Capacity value, CEO maintains that short-term market prices, even during IPC's "on-peak" periods, do not reflect the full value of both energy and capacity during those hours. As regulators in ERCOT have discovered, participants in "free markets" for energy services sell into the market when it is to their advantage. They do not have a duty to provide energy when needed the way an on-system capacity resource can or a party to longer-term bi-lateral power agreements is legally compelled to do. Even during high-load hours, short-term market prices (like those in the EIM) are not reflective of a "capacity" value.

While self-generators are also not under contract to provide power to IPC at any particular hour, they too do not avail themselves of access to a "free market": they sell to a single monopsony buyer. The ECR is already proposed to be lowered by a "non-firm" adjustment to reflect these market conditions.

► If the Commission were to accept a suggestion to reduce the generation capacity valuation on the assumption that EIM market prices reflect capacity value, CEO would request that, in symmetry, the "non-firm" adjustment should be removed.

Avoided Transmission & Distribution (VODER 4.3) – Future treatment of marginal transmission

► CEO requests that, in future ECR updates, because new transmission lines like B2H, SWIP-north, and Gateway West sections 8 & 9 are to be used to access remote generation sources, the costs for those marginal transmission lines should be treated in the same fashion as other marginal generation resources when quantifying the T&D capacity contribution of self-generation.

Avoided Line Losses (VODER 4.4) – Deny the proposed reduction

The last time that the parties met to discuss line losses was in IPC-E-18-15 when the Company agreed to use 8.1% of the avoided energy and capacity values to determine the ECR value for line losses.[8] In IPC-E-21-21, the Company was ordered to study and compare marginal line losses[9], which the VODER filed in June 2022 did not[10]. Parties raised concerns[11], and the Commission believed that further discussion would be fruitful[12]. No

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[6] Jan 22, 2019 ORDER NO. 19-021 at 20, [UM 1910 Order.pdf&il=true (state.or.us)]

[7] PAC-E-23-17, Rocky Mountain Power On-Site Generation Study, at 23.

[8] IPC-E-l 8-l 5 Settlement Agreement, p3: "Avoided Transmission & Distribution Line Losses. The avoided energy value and the avoided capacity value are increased by 8.1% to reflect the avoidance of transmission and primary distribution level line losses."

[9] IPC-E-21-21, Order 35284 at 20, the Commission found: "It is also reasonable to study the difference between using static or marginal losses and the magnitude of each as part of the valuation to be included in the ECR."

[10] The word "marginal" does not appear in the June VODER discussion of line losses. The October VODER study added a paragraph (p73-74) describing that the 2012 System Loss Study did not study marginal losses, that customer exports are higher during the spring and fall than in summer, thus "average line losses is most appropriate" for an ECR calculation.

[11] Marginal line losses are notably higher than average losses. "Considering losses on a marginal basis is more accurate and should be standard practice" as recommended in A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, p23; referenced in IPC-E-22-22.

such discussions occurred. Instead, the Company proposes in this docket to further reduce the line loss assumptions from the 5.8% proposed in IPC-E-22-22 to 4.4% (off peak) and 5% (on peak)[13]. We ask that the Commission decline this proposed reduction.

CEO requests -

- ► That the Company's proposal to decrease the line loss assumption be denied. The line loss calculation in the initial ECR and any updated ECR in 2024 shall be not less than 5.8%, which is the value proposed in IPC-E-22-22 and for which parties raised concerns that the methodology underestimates line losses.

Avoided Environmental Costs (VODER 4.5) – Monetizing Renewable Energy Attributes

There is a growing customer interest in both the supply of and demand for renewable energy attributes. The Company has been purchasing RECs at 0.71 cents per kWh and selling them for 1 cent per kWh under the Green Power Program,[14] and will continue offering renewable energy attributes under the Clean Energy Your Way programs. As the Company incurs costs to serve that market, the potential for utilizing customer-owned generation to avoid those costs is not zero. CEO is seeking in this docket to take the first steps on a path toward utilizing customer-owned resources to avoid costs as the Company serves the market for renewable energy attributes.

Below we first speak to the hurdles[15] identified by the Company (registering resources with WREGIS and transferring ownership of renewable energy attributes), then put forward specific requests.

The transfer of customers' ownership of renewable energy attributes is feasible. Per the October VODER Study, p79, "Idaho Power is not aware of any on-site generation or net metering arrangement in which a customer's export of energy back to the utility involves the transfer of the RECs or environmental attributes of those exports." While CEO lacks the resources to research all examples, a Rocky Mountain Power tariff demonstrates the feasibility of transferring ownership. As part of the Utah Solar Incentive Program (USIP), 2012-2016, a term included in the Rocky Mountain Power's tariff[16]:

> 8. Renewable Energy Certificates: The Company retains an ownership right in any Renewable Energy Certificate associated with a participating facility equal to 0.28 MWh/ per incentivized kW per year for 20 years.

The demand for renewable energy attributes is diverse and growing[17], and self-generators may offer a cost-effective resource to serve some needs. We note two opportunities: first, not all individuals or

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[12] ORDER NO. 35631, p 29: "We believe that additional discussion between Staff, Intervenors, and the Company on the topic of avoided line losses, during the implementation case, may be fruitful and potentially resolve any remaining issues or confusion surrounding the Company's calculation of avoided line losses."
[13] IPC-E-23-14 Ellsworth Direct, at 22.
[14] Idaho Power Response to CEO Production Request No. 2.
[15] The VODER study reports (p80), "It may be logistically possible for Idaho Power to aggregate and certify RECs from customer-generators, but there are several hurdles: 1) to register each customer-generator resource with WREGIS, at a minimum the customer would need to legally transfer ownership of the environmental attributes of their resource to Idaho Power and would be prevented from claiming the clean nature of the energy from the resource going forward; 2) Idaho Power would need to implement detailed recording and tracking of generation data; and 3) the company would need to pay a small monthly fee."
[16] Rocky Mountain Power Service Schedule NO. 107, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/107_Solar_Incentive_Program.pdf
[17] IPC-E-21-40 Application at 5. "In particular, commercial, industrial, and municipal customers are increasingly pursuing or exploring sustainability targets, such as powering their operations on 100 percent renewable energy by the end of the decade—if not sooner."

organizations willing to pay for renewable energy attributes may require that the attributes be certified as RECs. As an analogy, many consumers like organically grown food, not all want to pay a premium to have it certified as organic. While certification may be a requirement to many organizations to meet their reporting needs or targets, a product that does not carry the added costs of certification may cost-effectively serve the needs of some customers, particularly residents. As of December 2022, the Company reports 4,126 Idaho Residents purchasing renewable energy attributes via the Green Power Program[18]. Some of those customers may value an option to purchase renewable attributes of exports from self-generators in their community even if those exports were not formally certified by Green-e or other entity.

Secondly, the Company asserts hurdles related to registering resources with WREGIS and tracking generation data, yet the VODER study has not determined these are insurmountable for all customer-owned generation. Larger projects offer more economies of scale, the Company tracks export data, and the technologies for efficiently tracking generation data continue to improve.

The VODER study has identified solvable issues regarding the monetization of renewable energy attributes; this implementation docket should ensure a process for addressing those issues.

► CEO's requests aim to solve what's solvable in this docket and to ensure a process for ongoing evaluation of opportunities to utilize customer-owned generation in the market for renewable energy attributes:

1) As a first step toward creating a platform for potential compensation to residents for renewable energy attributes, Schedule 6 should be modified such that customers transfer ownership of the renewable energy attributes of their exports to the Company. CEO would support that Schedule 6 allow customers to opt out of this transfer if the interest in an opt-out outweighs administrative matters associated with offering it. Supporting logic includes:
   - Residents currently have little opportunity to monetize the value of renewable energy attributes without the centralized economies of scale offered by the utility.
   - Residents and parties have commented that exports have an environmental value, which implies the environmental attributes flow with each kWh exported.
   - As demonstrated by Rocky Mountain Power, transfer of ownership is feasible.
   - While business interests could conceivably do so, there is no practical concern of residents double-counting their claim to renewable energy attributes.
   - The Company raised concerns with implementing "detailed recording and tracking of generation data"[19] associated with certified REC's. This proposal creates an alternative renewable energy product which does not require tracking of generation data, only exports.
   - CEO could support - though is not proposing - a similar term for Schedule 84 at this time. The size of Schedule 84 projects affords a growing opportunity for them to certify their generation and to benefit from an instrument to sell renewable energy attributes of generation, not just exports.

2) CEO requests that the Company be directed to evaluate opportunities for customer-owned generation to provide a resource for avoiding the costs of serving potential Clean Energy Your Way (CEYW) Flexible customer needs. One option to evaluate would be for CEYW- Flexible to add an option such that participants could choose to purchase the renewable energy attributes associated with customer-owned renewable energy exports. Alternatively, for larger customers, certification of customer-owned generation may be cost effective. Further evaluation is merited to identify what it would take to cost-effectively utilize customer-owned generation as a resource for CEYW Flexible needs.
   - **Costs could be avoided**. For the year 2022, the Company purchased 37,519 MWh renewable energy certificates at an expense of $266,379.34 to fulfill the needs of the Green Power Program[20]. The October

[18] Idaho Power Response to CEO Production Request No. 2.
[19] VODER study, p80, filed with IPC-E-23-14
[20] Idaho Power Response to CEO Production Request No. 2.

VODER study reports 59,155 MWh of real-time exports of renewable energy (Appendix 4.6).

- CEO observes from Order 35893 (at 23), "the Commission directs the Company to host a workshop on the CEYW costs, revenues, and loads in base rates within one hundred twenty (120) days of the issuance date of this Order." Such workshop offers one option to frame opportunities and identify needs for further evaluation.

3) CEO requests that, as part of the annual ECR update, the Company should report on opportunities to monetize the value of renewable energy attributes of exports (non-certified) as well as opportunities for aggregation and/or certification of customer-owned generation. More generally, CEO is asking that a placeholder be defined to ensure ongoing evaluation of opportunities to monetize the value of renewable energy attributes of customer-owned resources, and that ECR methodology should retain an annual calculation of environmental benefits.

Integration Costs (VODER 4.6) – Scenario 9 is now more accurate than Scenario 1

The VODER methodology uses a 2020 Variable Energy Resources ("VER") Integration Study, which assesses integration costs for various case scenarios. Below is the table from that 2020 study summarizing case scenarios for 2023[21]:

Table ES1: Case Description and Results Summary

						Amount of New VER Added to Existing 2023 Builds				
Case	Description	First Bridger Unit	Proposed Existing 2023 Solar Capacity (MW)	Proposed Existing 2023 Wind Capacity (MW)	Hydro Year	New 2023 Solar Build (MW)	New 2023 Wind Build (MW)	Can New Solar be Curtailed?	New Solar-Coupled 4-hr Li-Ion Battery Build (MW)	Total Integration Cost
1	Base 2023 Case	Retired	561	728	Normal	0	0	No	0	$ 2.93
2	Base Case + First Bridger Unit Online	Online	561	728	Normal	0	0	No	0	$ 3.61
3	High Solar	Retired	561	728	Normal	794	0	No	0	$ 3.86
4	High Solar, Low Hydro	Retired	561	728	Low	794	0	No	0	$ 4.55
5	High Wind	Retired	561	728	Normal	0	669	No	0	$ 0.77
6	High Solar, High Wind	Retired	561	728	Normal	794	669	No	0	$ 2.46
7	Existing Solar Base Case	Retired	310	728	Normal	0	0	No	0	n/a
8	High Solar, High Hydro	Retired	561	728	High	794	0	No	0	$ 4.65
9	High Solar + 200 MW Storage	Retired	561	728	Normal	794	0	No	200	$ 0.64
10	High Solar + 400 MW Storage	Retired	561	728	Normal	794	0	No	400	$ 0.93
11	Curtailable Solar	Retired	561	728	Normal	794	0	Yes	0	$ 3.13

A question before the Commission in this docket is which Case scenario in the 2020 Integration Study is most applicable for the determination of integration costs. The Company proposed Case 1, which assumes implementation of ZERO battery storage. This no longer reflects current resources. As noted in a March 2023 news release by Idaho Power[22] -

- An 80-megawatt (MW) battery energy storage system is being installed at the company's Hemingway substation in Owyhee County
- A 40-MW battery energy storage system is being built adjacent to the 40-MW Black Mesa solar project in Elmore County.

[21] Appendix 4.17 - Idaho Power 2020 VER Integration Study, Page 5 of 88

[22] https://www.idahopower.com/news/idahos-largest-energy-storage-projects-under-construction-more-solar-on-the-way/

- A 60-MW four-hour duration battery energy storage system owned and operated by Idaho Power will be part of the Franklin solar project. Pending approval by the IPUC, the Franklin project is scheduled to come online in 2024.

Case 9 assumes implementation of 200MW of storage, which is more consistent with current resources, the 2021 IRP, and the 2023 IRP.

► CEO requests that the proposed ECR be updated to reflect the integration costs of $.64/MWh associated with Case 9 rather than the $2.93/MWh the Company proposed.

Schedule 84 Project Eligibility Cap (VODER 9) – Support for Company proposal

CEO supports the IPC-E-23-14 proposed changes to the Schedule 84 project eligibility cap, which will allow customers to right-size projects, avoid the inefficiency of having to install multiple 99kW projects across numerous locations in order to offset high loads on a single meter, and will remove the competitive disadvantage of a low cap system size cap relative to utilities in other states. CEO supports implementing this change to Schedule 84 changes as soon as possible to allow customers more freedom to manage their energy costs.

Dated this 12th day of October, 2023.

Courtney White

Managing Director

Clean Energy Opportunities for Idaho

CERTIFICATE OF SERVICE

I hereby certify that on this 12th day of October, 2023. I delivered true and correct copies of the foregoing COMMENTS to the following persons via the method of service noted:

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