Office of the Secretary
Service Date
February 17, 2026

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2025 INTEGRATED RESOURCE PLAN	)	**CASE NO. IPC-E-25-23**
	)	**ORDER NO. 36937**

On June 27, 2025, Idaho Power Company ("Company") applied to the Idaho Public Utilities Commission ("Commission") requesting that the Commission issue an order acknowledging the Company's 2025 Integrated Resource Plan ("IRP") ("Application").

On August 11, 2025, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 36706. The Commission granted intervention to Micron Technology, Inc., Idaho Irrigation Pumpers Association ("IIPA"), Northwest Energy Coalition and Renewable Northwest ("NWEC/RNW"), and Renewable Energy Coalition ("REC"). Order Nos. 36717, 36740, 36751, and 36758.

On October 6, 2025, the Commission issued a Notice of Modified Procedure establishing comment deadlines. Order No. 36786. Commission Staff ("Staff"), IIPA, and NWEC/RNW filed comments. The Commission also received three public comments. The Company filed reply comments.

On December 23, 2025, IIPA filed an Application for Intervenor Funding in the amount of $16,688.29.

Based on our review of the record, we now issue this Order acknowledging the Company's 2025 IRP, as described herein, and granting IIPA's Application for Intervenor Funding.

THE APPLICATION

The Company stated that its 2025 IRP represents a comprehensive analysis of the optimal mix of both demand- and supply-side resources available to reliably serve customer demand and flexible capacity needs from 2026 to 2045. Application at 1–2. According to the Company, it used Energy Exemplar's Aurora Long-Term Capacity Expansion ("LTCE") modeling tool to develop portfolios that are least-cost, least-risk for a variety of alternative future scenarios. *Id.* at 2.

The Company had four primary goals for its 2025 IRP. *Id.* at 4. Firstly, the Company sought to identify sufficient resources to meet the anticipated growing demand for energy within the Company's service area throughout the 2026–2045 planning period. *Id.* Secondly, the Company wanted to ensure its Preferred Portfolio reasonably balanced cost and risk, while adhering to relevant environmental regulations. *Id.* Next, the Company sought balanced consideration of supply-side resources, demand-side measures, and transmission resources. *Id.* Finally, the Company sought to meaningfully engage the public in the planning process. *Id.*

According to the Company, two notable trends emerged in the 2025 IRP: (1) the essential need for added transmission and flexible resources and (2) the unpredictability of additional load growth stemming from heightened uncertainty surrounding state and federal policy. *Id.* at 9.

The Company identified key branches of the 2025 IRP to evaluate in additional detail, and the Company required the model to build portfolios both with and without each branch. *Id.* at 11–12. The Company stated that the most impactful contingency scenario analyzed under the 2025 IRP is the potential repeal of the 2024-revised Environmental Protection Agency Rule 111(d) regarding carbon emissions for existing and new resources. *Id.*

In advance of finalizing the 2025 IRP, the Company held four technical workshops to address Staff's concerns regarding the 2023 IRP. *Id.* at 14. The Company believed the workshops successfully resolved Staff's previous concerns, including: "(1) future resource costs and Aurora resource selection; (2) Aurora resource selection and Aurora dispatch; (3) interconnection costs, REC price forecasts, and load percentile methodology; and (4) the timing of highest risk." *Id.*

The Company used its analysis to select a Preferred Portfolio, which included a mixture of generation resources, energy storage systems, and transmission. *Id.* at 12. According to the Company, the Preferred Portfolio is the least-cost, least-risk option that balances the need for clean, low-cost resources without compromising system reliability. *Id.* The Company further stated that its Preferred Portfolio adds "1,445 [megawatts ("MW")] of solar, 885 MW of storage (4-hour batteries, as well as 50 MW of long duration 100-hour storage), 700 MW of wind, 550 MW of new gas, 344 MW of incremental energy efficiency, and 20 MW of incremental demand response." *Id.* at 3. Additionally, the Company represented that the Preferred Portfolio involves converting multiple coal-fired generation units, currently representing 484 MW, to natural gas, adding a total of 611 MW of natural gas through 2045. *Id.* The Company stated that the Preferred Portfolio adds a total of 4,071 MW of incremental resource capacity over the 20-year planning period, including the Boardman-to-Hemingway ("B2H") transmission line as of December 2027; the Southwest Intertie Project-North transmission line as of November 2028; and the Midpoint – Hemingway #2 500 kilovolt with the first phase in 2028 and the second phase in 2030. *Id.*

The 2025 IRP includes the Company's Near-Term Action Plan ("NTAP"), which reflects the Preferred Portfolio's near-term actionable items. *Id.* at 12. According to the Company, the NTAP is critical to position the Company to provide reliable and economic service to its customers. *Id.*

STAFF COMMENTS AND COMPANY REPLY

1. Staff Comments

Staff recommended that the Commission acknowledge the Company's 2025 IRP and agreed that the Company's 2025 IRP meets the requirements of Commission Order Nos. 22299 and 25260. Staff Comments at 2, 14. Staff believed the Company's 2025 IRP satisfied Commission directives requiring electric utilities to (1) submit a biennial IRP considering existing resources, load forecasts, and future resources necessary to reliably serve the future load, and (2) factor public participation into the development of the plan. *Id.*; Commission Order Nos. 22299, 25260. Additionally, Staff supported the Company's selection of its Preferred Portfolio.[1] Staff Comments at 6–9, 14. However, Staff did not believe it is appropriate or necessary for the Commission to acknowledge the second sub-list ("2025 IRP Decisions for Acknowledgement") of the Company's NTAP, containing Company actions that have yet to be the subject of a separately filed case. *Id.* at 9–10. Staff also had numerous suggestions for the Company to consider for the next IRP. *Id.* at 3.

Staff recommended improvements to the Company's levelized cost of capacity ("LCOC") calculations, which Staff characterized as a fundamental input to the LTCE model. *Id.* Staff suggested the Company provide rationale for the overnight plant capital it uses for each resource. *Id.* Staff commended the Company's new approach of assigning a standard value to interconnection capital estimates and recommended the Company continue using this approach. *Id.* Staff also encouraged the Company to include a detailed discussion of resources requiring a capacity factor applied to the LCOC and the annual capacity factor values used for each resource that requires one in the next IRP. *Id.* at 4, 14. Lastly regarding LCOC calculations, Staff recommended the Company simplify and standardize the application of escalation factors. *Id.* at 4.

[1] Staff noted that Commission acknowledgement of the Company's 2025 IRP would not confer a prudence determination on resources included in the Preferred Portfolio and that future prudency determinations would depend on an evaluation of the Company's selection of resources based on conditions at the time of acquisition. Staff Comments at 2, 9.

Staff also suggested the Company's model constraints for new transmission lines may not sufficiently account for project delays. *Id.* at 5–6. According to Staff, transmission construction projects are particularly susceptible to delays. *Id.* at 6. Staff recommended the Company build delay into the modeled commercial operation date ("COD") for new transmission resources. *Id.* Staff proposed the Company accomplish this by: (1) adding up to 12 months to the modeled COD for projects facing unresolved permitting and/or right-of-way issues, or (2) modeling delays as a risk variable that would inform least-cost contingencies. *Id.*

Staff recognized the Company is facing challenges related to large load growth beginning in 2026 and continuing through at least 2031. *Id.* at 10. Staff encouraged the Company to engage the Commission when there is tension between the Company's obligation to serve new large loads and its obligation to provide fair, just, and reasonable rates prior to taking action that could limit the available options. *Id.*

Though Staff believed the Preferred Portfolio's Energy Efficiency ("EE") and Demand Response ("DR") measure selections and supporting methodology were generally reasonable, Staff suggested the Company provide additional details in future IRPs regarding its selection of EE measures. *Id.* at 11. Staff was particularly concerned with the Aurora model's selection of EE measures that were not expected to be cost-effective. *Id.*

According to Staff, the Public Utility Regulatory Policies Act ("PURPA") new development rates and replacement rates, which the Company used as part of its baseline assumptions regardless of where projects are located, does not sufficiently account for policy differences among the Company's service territories. *Id.* at 13. To more accurately reflect actual circumstances in baseline assumptions, Staff recommended the Company: (1) develop Idaho's PURPA new development and replacement rates separately using Idaho-specific data; (2) separately develop Idaho's PURPA new development and replacement rates for projects that use the Surrogate Avoided Resource ("SAR") method and for those that use the Incremental Cost IRP ("ICIRP") method; and (3) contact expiring Idaho projects to gain understanding of project renewal intentions, when the empirical data for determining replacement rates is insufficient or unavailable. *Id.*

Staff encouraged the Company to further explain the calibration process between the LTCE and the Reliability and Capacity Assessment Tool ("RCAT") models in its next IRP. *Id.* at 14. Specifically, Staff believed the Company should provide additional clarity regarding the adjustments to the seasonal Planning Reserve Margin ("PRM") and the Effective Load Carrying Capability ("ELCC") curve when the LTCE-developed portfolio results in a capacity shortfall in the RCAT model. *Id.*

Finally, Staff recommended the Company explore incorporating the Westen Energy Imbalance Market's flexible ramping requirement into the next IRP. According to Staff, the Aurora model does not capture sub-hourly inputs, and incorporating the flexible ramping requirement would help ensure the Company meets various reserve needs. *Id.*

2. Company Reply to Staff

The Company did not object to Staff's position that Commission acknowledgement of certain items included in the NTAP is not appropriate or necessary where separate filings regarding the same item already exist. Company Reply Comments at 4.

The Company supported Staff's recommendations that the next IRP provide rationale for the overnight plant capital selected for each resource and the annual capacity factor values selected for each resource that requires one. *Id.* at 4–5. Though the Company believed its method for applying escalation factors to LCOC calculations in the 2025 IRP was reasonable and consistent with industry standards, it agreed to work with Staff and the IRP Advisory Council to explore a more standardized approach, as Staff recommended. *Id.* at 5–6.

The Company agreed with Staff that new transmission lines are susceptible to legal and regulatory delays. *Id.* at 6. The Company stated that it would update transmission assumption with material changes in the next IRP and work with Staff and the IRP Advisory Council to improve transmission assumption. *Id.*

In anticipation of expected large load growth beginning in 2026, the Company committed to engaging with the Commission in situations requiring trade-offs between the Company's obligation to serve customers and its obligation to maintain fair, just, and reasonable rates, as Staff suggested. *Id.* at 7.

The Company understood Staff's concern regarding the Aurora model's selection of EE measures that were not expected to be cost-effective. Though the Company stated the selections were the lowest cost bundles of measures available, it expressed its willingness to explore whether making these types of resources available for selection is advisable. *Id.* at 7–8.

The Company agreed with Staff's recommendations to explore developing Idaho's PURPA new development and replacement rates separately using Idaho-specific data in recognition of differing policy environments among the jurisdictions within the Company's service territory. *Id.* at 8–9. The Company stated that differences in contract lengths available to SAR and ICIRP projects were already factored into such rates in the 2025 IRP but committed to evaluating additional methodological changes to further capture the differences between SAR and ICIRP pricing and terms and conditions in the forecast of PURPA generation. *Id.* at 9. The Company also agreed to contact expiring Idaho projects to gain understanding of project renewal intentions. *Id.*

In response to Staff's recommendation that the Company further explain the calibration process between the LTCE and the RCAT models in its next IRP, the Company stated that it would provide more detail regarding adjustments related to the seasonal PRM and ELCC curves. *Id.* at 10.

Finally, the Company represented that the Aurora model already captures sub-hourly inputs for reserves and flexibility. *Id.* at 11. The Company stated that it was confident WEIM's flexible ramping requirements were captured in its modeling. *Id.*

INTERVENOR COMMENTS AND COMPANY REPLY

1. IIPA Comments

IIPA believed the 2025 IRP demonstrated the Company's understanding of the evolving western energy markets. IIPA Comments at 1. However, IIPA also believed the Company's NTAP was flawed in several ways. *Id.* IIPA recommended that the Commission decline to acknowledge the 2025 IRP, "or at minimum, the Commission should expressly note the plan's instability and the substantial risk of cost misallocation" for the following reasons. *Id.* at 10.

According to IIPA, the 2025 IRP incorrectly attributed reliability and transmission needs to summer peaks, while failing to identify winter adequacy concerns caused by new load due to large customers as the true drivers. *Id.* at 2. IIPA recommended the Commission expressly acknowledge that capacity and transmission costs are being driven by winter demand large load customers, not by summer-only customers (such as seasonal irrigators). *Id.* at 2, 4. IIPA argued that new, year-round industrial demand eliminates the seasonal headroom that has previously allowed the Company's system to accommodate irrigation peaks without new infrastructure. *Id.* at 6. Irrigation load has remained consistent according to IIPA. *Id.*

Therefore, IIPA asked the Commission to note that new large loads are causal factors in the Company's need to acquire resources, including the Southwest Intertie Project-North ("SWIP-N"), Gateway West ("GWW"), and Mayfield. *Id.* at 5. IIPA argued that the record shows that

Company's new large industrial load requests are the overwhelming factor driving incremental transmission needs across the Company's system. *Id.* at 3. IIPA also represented that the NTAP fails to consider the implications of potentially withdrawn new large industrial load requests, exposing existing ratepayers to the risk of significant stranded costs. *Id.* at 3–4.

IIPA also requested "[t]he Commission recognize that the IRP's resource plan is contingent on infeasible or outdated project assumptions." *Id.* at 5. According to IIPA, the Jackalope wind project appears infeasible, and the NTAP fails to address this likely outcome.[2] *Id.* at 3. IIPA also stated that the Company's pending application for Certificate of Public Convenience and Necessity ("CPCN") for the Bennet Gas Expansion Project in Case No. IPC-E-25-29 uses the 2023 IRP capacity analysis and makes no reference to the 2025 IRP. *Id.*

Furthermore, IIPA recommended the Commission expressly state that it has not acknowledged B2H, GWW, Mayfield, or new generation and storage resources identified in the 2025 IRP's NTAP. *Id.* at 5. IIPA contended that the Company did not present these major transmission and generation additions as actionable items. *Id.* at 3. IIPA believed the Commission should observe that prior acknowledgements are inapplicable as to new actions described in the NTAP. *Id.* at 5.

2. Company Reply to IIPA

The Company believed IIPA raised several issues that are beyond the scope of an IRP filing and would be more appropriately addressed by a separate proceeding. Company Reply Comments at 22–23.

The Company disputed IIPA's claim that the 2025 IRP's modeling incorrectly attributed reliability and transmission needs to summer peaks. *Id.* at 23. According to the Company, the available transmission capacity during summer is objectively lower than during non-summer. *Id.* According to the Company, neighboring utilities reserve transmission capacity to serve greater system demands during summer, limiting the Company's ability to import or export energy. *Id.* Additionally, the Company stated that warmer conductors and higher demand result in greater line losses in the summer. *Id.* The Company also noted that the Preferred Portfolio seasonal LOLE analysis showed higher summer risk in all years throughout the planning period. *Id.* at 28.

[2] On December 31, 2025, the Commission issued Order No. 36893, in which it granted the Company's petition to withdraw the Certificate of Public Convenience and Necessity for the Jackalope Wind Project due to permitting delays and uncertainty concerning federal land use policies.

In response to IIPA's contention that the 2025 IRP risks stranded costs by failing to adequately account for the possibility of delayed or failed large industrial loads, the Company reiterated that its load forecast included only customers that have made a significant binding investment or have expressed "interest indicating a commitment of the highest probability of locating within the service area." *Id.* at 24–25. The Company also argued that, while cost recovery is not appropriately reviewed during an IRP proceeding, other dockets and the terms of special contracts serve to mitigate stranded cost risk. *Id.* at 25.

The Company stated that the NTAP includes the 600 MW Jackalope wind project because there were no indications that federal permitting changes would pause the project when the 2025 IRP was developed. *Id.* at 25–26. Contrary to IIPA's position, the Company argued it would be unreasonable to deem the 2025 IRP as incomplete due to circumstances arising after the planning period. *Id.* at 26.

The Company also disputed IIPA's claim that the 2025 IRP is inconsistent with the Company's request for a CPCN in Case No. IPC-E-25-29. *Id.* The Company stated that a system reliability assessment with updated load and resource inputs performed after the 2025 IRP was the basis for the Company's CPCN request for the Bennett Gas Expansion Project. *Id.* at 27.

In response to IIPA's concern that transmission projects were not presented as actionable items in the NTAP, the Company stated that B2H and GWW were included in all scenarios because they were committed to prior to the 2025 IRP or because of their universal need. *Id.* The Company represented that it modeled a "no-SWIP" scenario that was compared to the Preferred Portfolio. *Id.* at 28. The Company also disputed IIPA's contention that the need for transmission projects was attributable to new industrial load. *Id.* The Company argued the projects support broader system reliability and capacity. *Id.*

3. NWEC/RNW Comments

Though NWEC/RNW believed the Company's approach to resource planning incorporated many best practices, they argued there are areas where the Company's approach should be improved. NWEC/RNW Comments at 1. Specifically, NWEC/RNW contended the Company's could implement improvements concerning resource cost assumptions; assessments of thermal reliability, fuel supply, and price fluctuations; transparency and flexibility for new large loads; and a thorough evaluation of each portfolio's risks. *Id.*

NWEC/RNW had four concerns regarding the Company's resource cost assumptions: (1) understated gas-fired resource costs; (2) overstated wind costs; (3) overstated storage resource costs; and (4) unrealistic future costs escalation factors. *Id.* at 2. First, NWEC/RNW argued that the Company's cost assumptions for new combined cycle combustion turbines and simple cycle combustion turbines were approximately 25% below the published benchmark data from a recent study due to lag behind the current market conditions. *Id.* at 3. NWEC/RNW then contended that the Company assumed the highest cost assumption for wind generation of any source they reviewed, with a 30% premium over the median of all sources surveyed. *Id.* at 4. Next, NWEC/RNW stated that the Company's assumed costs for storage resources were 15%–45% above the 2023 IRP and the sources they reviewed. *Id.* at 5. According to NWEC/RNW, the Company used escalation factors that failed to adequately account for battery storage cost reductions due to generally accepted technology maturity curves. *Id.*

NWEC/RNW believed the Company's planning omitted key reliability concerns for thermal resources and that its reliance on new thermal capacity subjects the system to fuel price volatility and supply risks. *Id.* at 6–7. NWEC/RNW maintained that classical reliability metrics are poorly suited for evaluating thermal resources and that the Company should comprehensively assess thermal resource reliability, including fuel supply curtailment and price volatility risks. *Id.* at 6–7. NWEC/RNW noted that the Company's "Low Gas Price" portfolio and "High Gas & Carbon Prices" portfolio respectively resulted in the lowest and highest total costs of all portfolios considered, demonstrating the disproportionate risk introduced by increased reliance on thermal generation. *Id.* at 7–8.

NWEC/RNW recommended the Company and the Commission create more transparency and flexibility for new large load forecasts. *Id.* at 10. According to NWEC/RNW, the 2025 IRP does not address the risk of over-procurement and stranded assets associated with unprecedented growth forecasts. *Id.* at 10–11. Though the Company represented it is only including new industrial customers that have made a "significant binding investment" or have indicated "a commitment of the highest probability," NWEC/RNW believed the Company should provide further clarification as to the definition of these terms in the next IRP. *Id.* at 11. NWEC/RNW also asserted that increased demand-side flexibility from new large load customers could significantly curtail the need for additional generation capacity, reducing reliability and planning risks. *Id.* at 12. NWEC/RNW believed the Company's data regarding loss of load expectations by hour indicated substantial opportunity to shift loads to off-peak hours and referenced other jurisdictions that have recently announced agreements that will enable DR capabilities in data centers.[3] *Id.*

Finally, NWEC/RNW recommended the Company update its approach to risk assessment and documentation to enable a full assessment of portfolio options. *Id.* at 14. NWEC/RNW suggested the Company's Qualitative Risk Analysis should include clear values to define low, medium, and high risk, and should be expanded to additional future portfolio sensitivities. *Id.* NWEC/RNW suggested the Company's Stochastic Risk Analysis should better quantify each portfolio's sensitivity to key inputs. *Id.* NWEC/RNW recommended the Company develop a portfolio scorecard containing metrics determined through collaboration with the IRP Advisory Council. *Id.* at 14–15.

4. Company Reply to NWEC/RNW

The Company disputed NWEC/RNW's contentions regarding the 2025 IRP's resource cost assumptions. Company Reply Comments at 11. According to the Company, its cost assumption inputs were "informed by bid- level data from recent competitive solicitations and commercial discussions and benchmarked against reputable public sources… as well as Idaho Power's own procurement experience." *Id.* at 11–12. The Company stated that some of the materials NWEC/RNW cited to question the validity of cost assumptions used in the 2025 IRP were published after the assumptions were set and could not have reasonably been considered during the planning stage. *Id.* at 12.

The Company also challenged NWEC/RNW's position regarding reliability considerations for thermal resources and increased reliance on new thermal capacity due to fuel price volatility and supply risk. *Id.* at 13. The Company stated that it relied on five-year rolling average published data regarding forced outage rates for these reliability assumptions. *Id.* at 13–14. According to the Company, the historical values account for any degradation resulting from more frequent cycling and integration, any disruption on pipelines, or extreme cold events. *Id.* at 14. The Company also contended that the 2025 IRP sufficiently accounted for risks related to fuel price volatility and deliverability by adding resource diversity—both in terms of generation type and sourcing for the Company's natural gas supply. *Id.* at 14–15. Additionally, the Company represents that it included

[3] Specifically, NWEC/RNW identified agreements between Google and Indiana Michigan Power and Tennessee Valley Authority that were announced in August 2025.

a wide range of natural gas prices in its stochastic analysis, which supported selection of the Preferred Portfolio, even when accounting for fuel price volatility. *Id.* at 15.

In response to NWEC/RNW's recommendation that it consider increased demand-side flexibility from large loads, the Company stated that it was willing to continue exploring creative solutions to address unprecedented load growth. *Id.* at 17. The Company stated specific ratemaking and tariff design options should be addressed in separate proceedings and not during the IRP filing. *Id.* The Company noted that it continues to discuss DR programs and load flexibility with large load customers while arranging special contracts, pursuant to the Commission approved Schedule 19 for loads in excess of 20 MW. *Id.* at 17–18. Furthermore, the Company represented that it vets large load commitments to guard against speculative requests that might result in over-procurement of resources. *Id.* at 18.

5. REC Comments

REC had concerns regarding the Company's plan to abandon existing wind and solar resources. REC Comments at 1. REC argued that the Company's use of a 28% renewal/replacement rate over the 20-year planning period for wind and solar was neither reasonable nor accurate. *Id.* at 2. REC represented that the Company planned to drop 487 MWs of existing wind capacity over the planning period. *Id.* REC recommended that the Commission find the Company's wind and solar methodology is imprudent and order the Company to adjust its wind and solar renewal methodology in future IRPs. *Id.*

According to REC, existing facilities typically attempt to avoid transmission costs associated with selling to a distant utility by continuing to sell to their interconnected utility. *Id.* at 4. REC stated that 100% of the wind projects it contacted indicated an intent to renew their contract with the Company. *Id.* at 6. However, REC believed the Commission's policies regarding published rates and contract length—which were implemented when the Company had a capacity surplus—would negatively affect wind and solar renewal rates and that it should reconsider those policies in separate dockets. *Id.* at 6–9.

REC also argued that utilizing existing resources provides several benefits over reliance on more expensive new generation, including avoidance of "permitting risks, fuel risks, tariff risks, Federal tax credit risks, construction risks, equipment procurement risks, transmission study risks, and completion schedule risks." *Id.* at 5.

6. Company Reply to REC

The Company disagreed with REC's argument that the 2025 IRP modeling included an unreasonable wind and solar PURPA contract replacement rate.[4] Company Reply Comments at 19. According to the Company, it uses data-driven assumptions where available—as directed by the Commission—and assumes a 75% replacement rate for resources where no existing contracts have expired—as directed by the Oregon Public Utility Commission. *Id.* at 19–20. The Company stated that it continues to use the 75% replacement assumption for expiring contracts based on the term lengths available in each state. *Id.* at 20. The Company argued that its experience contradicts REC's anecdotal representation that 100% of existing wind facilities would enter into replacement contracts with the Company. *Id.* Furthermore, the Company contended that its procurement decisions are based on the most up-to-date information and that if more replacement contracts have been signed than were previously anticipated, the Company can adjust its procurement efforts. *Id.* at 21.

PUBLIC COMMENTS AND COMPANY REPLY

1. City of Boise City ("City")

The City supported the 2025 IRP Preferred Portfolio's addition of solar, wind, and storage resources and its planned exits from coal-fired generation. City Comments at 1. However, the City was concerned about the addition of new natural gas capacity. *Id.* The City encouraged the Company to further incorporate climate-driven risks into future IRPs. *Id.*

2. Clean Energy Opportunities for Idaho ("CEO")

CEO, which was part of the Company's 2025 IRP Advisory Council, believed the Company could make improvements to future IRPs to address new large load growth and the availability of new resource types. CEO Comments at 1. CEO stated that new solar resources have changed the cost to serve analysis, noting that energy costs are now lower at mid-day and higher at night. *Id.* To take advantage of this change, CEO recommended the Company "ensure that the portfolio of options modeled reflect the most significant and feasible demand-side opportunities for minimizing future customer cost increases." *Id.* at 4. CEO believed these demand-side measures should include adequate time-of-use pricing incentives for irrigators, commercial, industrial, and large load customers based on a diurnal cycle focused cost distribution. *Id.* at 4, 6.

[4] The Company noted that while REC sometimes used the term "renewal," "replacement" is more accurate, because even existing resources enter into new contracts. Company Reply Comments at 19.

3. Douglas James

Mr. James was concerned about the Company's planned investment in storage resources due to battery life, unreliability, and fire risks. Douglas James Public Comment at 1.

4. Company Reply to Public Comments

Although the Company agreed with several of CEO's positions concerning hourly pricing and seasonal capacity, it noted that large general and industrial customer pricing structures already include time-of-use pricing elements and that the 2025 IRP already assessed additional demand-side management potential. Company Reply Comments at 30. The Company added that its use of utility-scale batteries has significantly diminished the incremental capacity benefit of additional load-shifting programs. *Id.*

In response to the City's recommendation that the Company incorporate climate-driven risks, such as public safety power shutoff events into future IRPs, the Company stated that such events have generally occurred internal to the Company's system and not within the scope of resource adequacy planning. *Id.* at 31. However, the Company committed to working with stakeholders to determine how to incorporate mitigation measures that directly affect resource planning. *Id.*

IIPA'S APPLICATION FOR INTERVENOR FUNDING

IIPA's application includes an itemized list of expenses totaling $16,688.29—including expert witness fees and legal fees. IIPA Application for Intervenor Funding, Exhibit A. IIPA argued that these expenses were reasonably incurred given its full participation in the matter, including during the discovery process and through its preparation of extensive written comments. *Id.* at 1.

IIPA argued that the costs it incurred in this case constitute a financial hardship for the 501(c)(5) nonprofit association. *Id.* at 2. IIPA stated that it represents farming interests in eastern and central Idaho through voluntary contributions by its members—which have been falling. *Id.* IIPA stated that due to its financial constraints, its participation was focused and prudent. *Id.* at 3.

IIPA also noted that its recommendations—which included suggestions that the Commission make explicit findings regarding infeasible project assumptions and the drivers of incremental costs of transmission resources—materially differed from Staff's recommendations. *Id.* IIPA represented that the issues addressed through its participation in the case concerned the Company's general body of customers. *Id.*

COMMISSION FINDINGS AND DECISION

1. Company's IRP

The Company is a public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code, including *Idaho Code* § 61-501. Having reviewed the record, the Commission finds that the Company's 2025 IRP satisfies the requirements in the Commission's prior orders, and the Commission acknowledges the 2025 IRP. However, the Commission notes that it is not acknowledging the second list, labeled "2025 IRP Decisions for Acknowledgment," contained in the Company's NTAP and located on pages 140–141 of the 2025 IRP.

We appreciate the Company's commitment, as expressed in its Reply Comments, to work collaboratively with Staff and other interested parties to improve the IRP planning process. We anticipate the Company's next IRP will incorporate much of the feedback from this case. Particularly, the next IRP should demonstrate that sub-hourly inputs for reserves and flexibility are captured in the Auroa model. The Commission also expects the Company to use the most recent and robust data to inform the cost assumptions included in portfolio modeling. Additionally, we encourage the Company to continue to explore all cost-effective measures designed to reduce the impact of expected load growth, including a comprehensive review of plausible demand-side flexibility.

In acknowledging the 2025 IRP, the Commission once again reiterates that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. An IRP is a plan, not a blueprint, and by issuing this Order we merely acknowledge the Company's ongoing planning process, not the conclusions or results reached through that process. The Commission recognizes the work that goes into designing and creating the IRP. Not just by the Company but also by the Intervenors, Staff, and the public at large. The IRP process and resulting IRP is more than just an exercise that results in a case before the Commission. While the Commission is only acknowledging the IRP, it expects to see more references to how the IRP has shaped decisions about the future and impacted operations. The Commission is also interested in how the near-term resource needs identified in this IRP are used and implemented in the future. If there are situations in which near-term resources become either impossible or uneconomic, the Commission is interested in knowing why and how that may influence subsequent IRPs.

The Commission does not approve the 2025 IRP, or any resource acquisition referenced in it, endorse any particular element in it, opine on the Company's prudence in selecting the 2025 IRP's preferred resource portfolio, nor allow or approve any form of cost recovery. The appropriate place to determine the prudency of the Company's decisions to follow or not follow the 2025 IRP, and the validation of predicted performance under the 2025 IRP, is a general rate case or other rate proceeding where the issue is noticed.

2. IIPA's Application for Intervenor Funding

Commission decisions benefit from robust public input. "It is hereby declared the policy of this state to encourage participation at all stages of all proceedings before the commission so that all affected customers receive full and fair representation in those proceedings." *Idaho Code* § 61-617A(1). Recoverable costs can include legal fees, witness fees, transportation, and other expenses so long as the total funding for all intervening parties does not exceed $40,000.00 in any proceeding. *Idaho Code* § 61-617A(2). The Commission must consider the following factors when deciding whether to award intervenor funding:

> (1) That the participation of the intervenor materially contributed to the Commission's decision;
> (2) That the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor;
> (3) The recommendation made by the intervenor differs materially from the testimony and exhibits of the Commission Staff; and
> (4) The testimony and participation of the intervenor addressed issues of concern to the general body of customers.

Id.

To obtain an award of intervenor funding, an intervenor must further comply with Commission's Rules of Procedure 161–165, IDAPA 31.01.01.161-165. Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for an application for intervenor funding. The application must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared. IIPA's application comports with the procedural and technical requirements of the Commission's Rules.

Commission Rule 165.02-.03 requires the payment of awards of intervenor funding to be made by the utility and is an allowable expense to be recovered from ratepayers in the next general rate case. IDAPA 31.01.01.165.02-.03.

We find that IIPA's application satisfies the intervenor funding requirements. IIPA intervened and meaningfully participated in all aspects of the proceeding in a manner that materially contributed to the Commission's final decision. IIPA's Application for Intervenor Funding was filed timely and no party objected to IIPA's request. We find the expert witness fees, legal fees, paralegal fees, and soft costs incurred by IIPA are reasonable in amount for this case, and that IIPA, as a non-profit organization, would suffer financial hardship if the request was not approved. Accordingly, we award IIPA its full request of $16,688.29 in intervenor funding which may be recovered by the Company from its Schedule 24, Irrigation customer class.

ORDER

IT IS HEREBY ORDERED that the Company's 2025 IRP is acknowledged.

IT IS FURTHER ORDERED that IIPA's Application for Intervenor Funding is granted in the amount of $16,688.29. *See Idaho Code* § 61-617A(2), IDAPA 31.01.01.165.01. The Company is ordered to remit said amount to IIPA within twenty-eight (28) days from the date of this Order. IDAPA 31.01.01.165.02. The Company shall be permitted to recover the cost of this intervenor funding in its next general rate case from its Schedule 24, Irrigation customer class. *See Idaho Code* § 61-617A(3).

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon 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. *Idaho Code* §§ 61-626.

DONE by order of the Idaho Public Utilities Commission at Boise, Idaho this 17th day of February 2026.

EDWARD LODGE, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

DAYN HARDIE, COMMISSIONER

ATTEST:

Monica Barrios-Sanchez
Commission Secretary
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