ORDER NO. 25-503

ENTERED Dec 09 2025

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 87

In the Matter of IDAHO POWER COMPANY, 2025 Integrated Resource Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED WITH MODIFICATION

This order memorializes our decision, made and effective at our December 9, 2025 Regular Public Meeting, to adopt Staff's recommendation in this matter as modified. We modify Staff's recommendation 4 (also set forth as the third bullet in the conclusion) to replace the words "trigger points" with the words "the conditions." The Staff Report with the recommendation is attached as Appendix A.

Made, entered, and effective Dec 09 2025.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

ITEM NO. RA2

PUBLIC UTILITY COMMISSION OF OREGON
REDACTED STAFF REPORT
PUBLIC MEETING DATE: December 9, 2025

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: December 2, 2025

TO: Public Utility Commission

FROM: Benedikt Springer

THROUGH: Caroline Moore and Kim Herb **SIGNED**

SUBJECT: IDAHO POWER COMPANY:
(Docket No. LC 87)
2025 Integrated Resource Plan.

STAFF RECOMMENDATION:

Staff recommends that the Commission acknowledge Idaho Power's IRP with the condition the Company provide a concrete plan regarding Bridger Units 3 and 4 in its next IRP, including how coal will be removed from Oregon rates, and adopt the Staff recommendations set forth in the conclusion of this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (Commission) should acknowledge Idaho Power Company's IRP, with or without conditions, and give the Company direction for its next IRP and RFP.

Applicable Rule or Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon's

[1] Docket No. UM 180, Order No. 89-507, April 20, 1989.

regulated utilities before the Commission considers acknowledgement of a utility's resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

Finally, Idaho Power Company's previous IRP, LC 84, resulted in Order No. 24-285, which provided specific directions to the Company on analytic matters.[9]

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2 Docket No. UM 1056, Order No. 07-002, January 8, 2007; Order No. 07-047 (correction), February 9, 2027. Additional refinements to the process have been adopted: See Docket No. UM 1302, Order No. 08-339, June 30, 2008 (IRP Guideline 8 later refined to specify how utilities should treat carbon dioxide (CO_2) risk in their IRP analysis); Docket No. UM 1461, Order No. 12-013, January 19, 2012 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).

3 Guidelines 1(c) and 3(a), OAR 860-027-0400.

4 Guideline 4(n).

5 Guideline 1(a).

6 Docket No. UM 1056, Order No. 07-002, January 8, 2007, p. 24ff.

7 Docket No. LC 58, Order No. 14-253, July 8, 2014, p. 1.

8 OAR 860-027-0400(7) and (10).

9 Docket No. LC 84, Order No. 24-285, Appendix A, August 26, 2024.

Analysis

Background

The Company filed its 2025 IRP on June 27, 2025, seeking acknowledgment for four Action Items.[10] The procedural schedule included a presentation by the Company at the public meeting on August 19, 2025, and two rounds of comments. Northwest Energy Coalition and Renewable Northwest (Joint Stakeholders),[11] the Renewable Energy Coalition (REC),[12] Staff,[13] and STOP B2H[14] filed Opening Comments. The Company replied on October 6, 2025.[15] Joint Stakeholders[16] and REC[17] filed Round 2 Comments, while Staff's Round 2 Comments stated it did not have additional issues at that time and that it would revisit outstanding issues in its Staff Report.[18] Staff thanks stakeholders for their engagement in this docket and the Company for its willingness to engage with Staff and stakeholders on the issues raised.

IRP Overview

Idaho Power's Preferred Portfolio adds 3,300 MW of new resources within the action plan window (2030), which includes 1,756 MW of already contracted resources. In total, the Preferred Portfolio adds 4,556 MW of new resources by 2045 and removes 484 MW through coal exits. Thermal (gas) additions are the minority with 1,061 MW in the short term, and 1,161 MW in the long term. This includes both new gas and the conversions of Valmy Units 1 and 2 from coal to gas in 2026, as well as the conversion of Bridger Units 3 and 4 from coal to gas in 2030. Within the action plan window, the portfolio selects 10 MW of additional DR, which the Company describes as enhancements of existing programs. Similarly, in the near term all energy efficiency comes from existing programs. Idaho Power's preferred portfolio also assumes that the Boardman to Hemingway transmission line (B2H) comes online in 2028 and the SWIP-N transmission line in 2029. Resource additions are mostly driven by new large loads, while residential demand is basically flat. The summer peak is forecast to grow by about 1,250 MW, or 32 percent, by 2032, about 200 MW per year on average from 2026 to 2032.

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10 Docket No. LC 87, 2025 Integrated Resource Plan, June 27, 2025.
11 Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Opening Comments, September 8, 2025.
12 Docket No. LC 87, Renewable Energy Coalition Opening Comments, September 11, 2025.
13 Docket No. LC 87, Staff Opening Comments, September 8, 2025.
14 Docket No. LC 87, STOP B2H Opening Comments, September 8, 2025.
15 Docket No. LC 87, Idaho Power Company Reply Comments, October 6, 2025.
16 Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Round 2 Comments, November 3, 2025.
17 Docket No. LC 87, Renewable Energy Coalition Round 2 Comments, November 3, 2025.
18 Docket No. LC 87, Staff Round 2 Comments, November 3, 2025.

Table 1: Preferred Portfolio

Resource	**2030**	**2045**
Coal Exits	-484	-484
Gas Conversions	611	611
Gas	450	550
Wind	700	700
Solar	745	1445
4h Battery	705	835
100h Battery	0	50
DR	10	20
EE Forecast	79	287
New EE	0	58
Total	3300	4556

The Company generally shows that its Preferred Portfolio is robust and outperforms other portfolios under a variety of conditions. Notably, the Company is currently planning with EPA rule 111(d) emission restrictions in place, despite the fact that this rule is likely to be rescinded.[19] Without the rule, the analysis shows that continuing Jim Bridger as a coal plant would be around one percent cheaper than the Preferred Portfolio. As seen in Action Item 2, the Company acknowledges that any plan regarding Bridger must be agreed upon with co-owner PacifiCorp.

Staff finds that the Preferred Portfolio is reasonably constructed and supports the proposed Action Items.

Action Item 1: Southwest Intertie Project-North (SWIP-N) Online by November 2028
The SWIP-N line runs from Southern Nevada to Idaho and is expected to provide Idaho Power with 500 MW south to north transmission capacity (year-round) starting in November 2028, which allows the IRP model to make additional economic market purchases up to the transmission limit. For resource adequacy, which is a separate constraint in Aurora, SWIP-N is assumed to provide 500 MW of winter capacity for resource adequacy purposes through market products. The Company models the impact of this line much like the treatment of the Boardman to Hemingway (B2H) line in

[19] The Environmental Protection Agency's (EPA) rules under section 111(d) of the Clean Air Act set emission guidelines for power plants and require states to develop plans for existing coal and gas plants to meet EPA's emission limits. 40 CFR Part 60. However, the EPA issued a proposed rule that would rescind all greenhouse gas emissions standards for fossil fuel-fired power plants. *See* Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units.

previous plans, comparing the revenue requirement of portfolios with SWIP-N to identical conditions without SWIP-N. The Without SWIP-N portfolio has a revenue requirement of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** more than the preferred portfolio.

Staff explored two issues regarding the SWIP-N transmission line. First, Staff wondered whether the California Independent System Operator (CAISO) would build SWIP-N without Idaho Power as an equity partner. It is imaginable that under such a scenario the Company would be able to rely on short-term transmission products in conjunction with market purchases for winter reliability, since the new transmission line might reduce congestion in the region regardless of ownership, increasing availability of short-term purchases. Idaho Power's modeling does not provide any analysis whether this hypothetical scenario might be more cost-effective than direct transmission ownership.[20] While Staff does not currently recommend any additional analysis to be conducted in the IRP, the appropriate assumptions to determine the value of SWIP-N might be discussed in cost recovery proceedings.

Second, Staff analyzed whether the assumption that the transmission line will allow the Company to make purchases of excess capacity of winter generation in the Desert Southwest (DSW) is reasonable. While the DSW region has an approximately 15 GW higher summer peak than winter peak, this does not take into account that solar will have lower generation in the winter as well. Staff found two data points that support Idaho Power's assumption. DSW solar capacity factors decline from 38.7 percent in July to 23.0 percent in January. This is less than the decline in peak demand.[21] Further, Idaho Power's one winter power purchase in 2024 from the Palo Verde market was priced at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[22] Though this is only one data point, the absence of extreme pricing in this transaction helps support the conclusion that excess capacity will be available for import. Since 2021, it has been difficult to make a bilateral purchase of power at that low a price during the winter in the Mid-Columbia market.

Overall, Staff finds this Action Item well justified and does not have concerns with it.

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20 Idaho Power Responses to OPUC Information Requests 16, 17, and 18.
21 Idaho Power Response to OPUC Information Request 15.
22 Idaho Power Response to OPUC Information Request 20.

Action Item 2: Pursue cost-effective existing demand response (DR) program expansion by 10 MW

Idaho Power's Preferred Portfolio selects an additional 10 MW of DR from existing programs in 2029, the first year Aurora was allowed to select this resource. This builds 10 MW on top of the existing Irrigation Peak Rewards, Flex Peak, and A/C Cool Credit programs, from which Idaho Power was able to dispatch around 257 MW of capacity in 2024.[23] This magnitude of existing DR capacity exceeds anything from Oregon's other two electric companies and Idaho Power's modeling pursues limited growth from existing levels, adding only an additional 10 MW beyond this action item in 2042. Idaho Power also modeled behind-the-meter storage, but Aurora did not select that new measure.

Staff finds that Idaho Power's DR modeling assumptions in Aurora are reasonable. The assumed capacity cost of the existing DR program is only $50 per kW-year, substantially lower than any supply-side resource.[24] The assumed capacity cost of distributed storage is $234 per kW-year, which is less than publicly available research estimates the cost of behind the meter storage (Lazard estimates this cost to be between $719 - $1,129 per kW-year).[25] Therefore, Staff does not see the overestimation of DR cost as the likely reason for Aurora's limited selection of DR.

The IRP provides insight into why DR is not a cost-effective incremental resource for Idaho Power. While DR is a low-cost resource, it also has a low ELCC of 19 percent.[26] Adjusting the cost by ELCC shows the selection of incremental DR from existing programs to be $260 per kW-year compared to over $1,200 per kW-year for distributed storage. Because DR shifts load onto other hours, the long duration of system risk throughout weekdays in July likely means that DR cannot provide much help in Idaho Power's highest risk month.[27] Aurora must then select other resources for July. Those resources tend to also be available for the rest of the year, crowding out months where DR could add value.

Idaho Power could increase the value of DR by dispatching it more frequently, but this would likely reduce participation in the program. This trade-off is something the Company should continue to evaluate. Aurora was restricted to adding DR starting in 2029. If DR could be added more quickly, which may or may not be realistic, it might

23 Idaho Power Company, 2025 IRP, Appendix B, June 27, 2025, p 8.
24 Idaho Power Response to OPUC Information Request 14, Attachment 1.
25 Lazard Levelized Cost of Energy +, June 2025, p 20.
26 Idaho Power Company, 2025 IRP, Appendix D, p. 11.
27 Idaho Power Response to OPUC Information Request 19, Attachment 1.

offer advantages over supply side resources with longer lead times. Staff encourages the Company to explore that further.

Overall, Staff believes the Company's plan for DR is reasonable and has no concerns with the Action Item, but does provide more discussion about future DR acquisitions in the section below on Action Item 4.

Action Item 3: Coordinate with PacifiCorp on the future of the Jim Bridger plant (Bridger) Units 3 & 4 given the Company's identified need for capacity and energy from Bridger Units 3 & 4

Idaho Power proposes to convert Jim Bridger units 3 and 4 to gas by 2030; however, majority-owner PacifiCorp proposes to convert it to carbon capture.[28] Staff is generally supportive of the approach proposed by Idaho Power but unclear how to reconcile what it sees as two very different futures envisioned by the co-owners. Idaho Power's IRP indicates that both a gas conversion and an exit from the plant is preferable over a carbon capture conversion, causing potential conflict with PacifiCorp. While Idaho Power currently plans under EPA rule 111(d), under a likely recission the Company finds continued coal operations only marginally cheaper. The situation is further complicated by the fact that SB 1547 requires coal to be removed from Oregon rates, without an exception for carbon capture.[29] The Company has not yet presented a plan for how to achieve that.

While Staff has no concerns with the Action Item, Staff believes the Company needs a more concrete plan by 2027. By then, the Company should have a more fleshed out strategy, supported by the IRP, which lays out not only the Company's preferred outcome, but also contingencies if the preferred outcome is not possible. The Company states in response to Staff questions that additional analysis would be necessary to determine such plans.[30] Staff believes that acknowledgment should be conditional on providing such a plan.

Much uncertainty surrounds the future of federal GHG emission rules. As such, Staff believes any decision regarding thermal resources should consider future regulatory risk. One way to support such consideration is to continue to include a scenario with a carbon policy proxy in IRP analysis, even if EPA rule 111(d) is repealed. An example of such analysis is the Company's stochastic results, which compare different portfolios

[28] PacifiCorp, 2025 IRP, March 31, 2025.
[29] ORS 757.518 (1)(b)(A) "Coal-fired resource" means a facility that uses coal-fired generating units, or that uses units fired in whole or in part by coal as feedstock, to generate electricity.
[30] Docket No. LC 87, Idaho Power Company Reply Comments, October 6, 2025, p. 3.

under random variation that includes carbon prices. In that analysis, the ninety-fifth percentile PVRR for the Bridger gas conversion is $450 million less than for continued coal operation.[31] In addition, Staff believes future analysis should include a more discrete comparison of portfolios under at least one scenario with and one scenario without carbon prices, which the Company is open to.[32] This could be achieved by identifying trigger points in the stochastic risk analysis, as suggested by Recommendation 4.[33] Furthermore, it will be important for the Company to clearly outline its decision criteria. For instance, it is currently unclear to Staff whether the Company prefers portfolios with the best average outcomes over portfolios that minimize the worst case. A Bridger gas conversion (better worst case) vs. continued coal operation (better average) with EPA rule 111(d) illustrates this trade off.

Overall, Staff has no concerns with this Action Item, but believes more analysis is required before the Company commits to any course of action regarding Jim Bridger. Staff recommends making acknowledgment conditional on such a plan due to the stark financial and legal implications of this choice. Additionally, for the 2027 IRP, Staff expects the Company to evaluate candidate portfolios with and without major federal policy drivers (e.g., carbon policy) and explain how that analysis supports the selection of the preferred portfolio as well as near-term actions.

Action Item 4: Pursue generation resources in 2029 and 2030 to meet forecasted needs, identified as natural gas, wind, solar, and storage
The Company's near-term procurement goals are well justified by the IRP, although the plan also highlights uncertainties regarding large loads that the RFP will have to address. While RFPs are approved in separate dockets, Staff memorializes three major issues here.

Given the fact that load growth is largely due to expected or signed Energy Service Agreements (ESA) with large customers, Staff expects that near-term RFPs include an updated forecast of ESA load and summarize the Company's level of certainty about the new ESA load. Idaho Power states that it:

> Intends to continue to include its most up to date ESA load forecast and will work with Staff as part of each case to provide a summary of such load's timing and probability (e.g., contract status, construction milestones,

31 Idaho Power Reply to OPUC Information Request 13, Attachment 1.
32 Docket No. LC 87, Idaho Power Company Reply Comments, October 6, 2025, p. 7.
33 Stochastic risk analysis refers to a process where the Company calculates how portfolio costs vary over 60 iterations where natural gas prices, customer load, hydroelectric generation, carbon prices, and REC price forecasts are changed randomly based on their historical or predicted variance.

> interconnection progress), and how those inputs translate into the evaluation of scenarios and resource needs.[34]

Given uncertainty regarding federal carbon policy, Staff expects near-term RFPs to consider regulatory risk explicitly, both as price and a qualitative factor. Idaho Power did this in previous RFPs and states that "the Company can provide a comparable analysis in upcoming near-term RFPs, should parties to such proceeding(s) request it."[35]

Given a rapidly changing landscape of DR technologies, RFPs should consider bids from DR developers, even if the IRP has not found it cost effective. New DR technologies and vendors are constantly emerging, which is difficult for internal DSM teams to track. In such a situation, RFPs may be able to surface new cost-effective options. In the past, all of the Company's RFPs have been open to any type of resource, although DR has not been called out explicitly. Additionally, "working with vendors and industry groups, the Company has investigated the cost and benefits of other customer DR opportunities such as a customer storage DR or Electric Vehicle DR and to date has not found that costs for those types of programs are low enough to compete with other resource options."[36] Nonetheless, Staff believes that the Company should explicitly consider how new DR solutions could be surfaced through RFPs. RFPs will likely require some additional design elements to be accessible to DR vendors. For instance, they might require details about the Company's current load shapes that are not generally made available.

Recommendation 1: The Company's next RFP should include a summary of large load timing and probability (e.g., contract status, construction milestones, interconnection progress) and consider carbon-related regulatory risk quantitatively and qualitatively.

Recommendation 2: The Company should bring a proposal to an IRP input meeting before the 2027 IRP for considering a DR RFP or better integrating DR into all source RFPs.

Overall, Staff finds that the IRP adheres to the procedural and substantive IRP Guidelines and that the IRP represents a reasonable least cost, least risk plan based on the information currently available. However, the production of a concrete plan regarding Jim Bridger Units 3 and 4 is an increasingly pressing issue and should hence be a condition of acknowledgement.

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34 *Ibid.*, p. 4.
35 *Ibid*. p. 5.
36 Idaho Power Response to OPUC Data Request 10.

Recommendation 3: Acknowledge Idaho Power's IRP under the condition that in its 2027 IRP, the Company provide a detailed plan regarding Jim Briger Units 3 and 4 that includes how coal will be removed from Oregon rates as well as contingencies for the case that the Company's preferred outcome is not feasible.

Concerns
Various issues were explored by Staff and stakeholders in this proceeding. None of the issues raised affect Staff's acknowledgment recommendations; however, in some instances Staff recommends the Commission give direction for the Company's next IRP.

Resource Costs
Joint Stakeholders argue that the Company's Preferred Portfolio is not least-cost, least-risk because they find that the Company underestimates gas costs, while overestimating costs of renewables. They recommend the Commission should not acknowledge the IRP unless the Company changes its resource assumptions.

Joint stakeholders claim that based on their review of publicly available data, SCCT and CCCT plants should be 20 percent more expensive. Furthermore, they argue costs of wind and battery capacity are overstated by 60 percent and 10 percent respectively. Joint Stakeholders elaborate, "if the underlying assumptions were determined just prior to a significant, foreseeable cost shift, it suggests the IRP's base case is immediately outdated and the resultant portfolio is suboptimal, further justifying our claim of significant variability and risk."[37]

In response, the Company notes that it developed resource assumptions through a transparent process and relies not only on public data bases, but RFP bid data as well. Furthermore, the Company explains while there may have been some cost escalation regarding gas components, stakeholders seem to disregard the expiration of production and investment tax credits, which will substantively increase renewable costs. Lastly, the Company argues that its preferred portfolio performs well under a variety of increased cost scenarios. The table below compares the Company's assumptions with two public databases.

[37] Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Round 2 Comments, November 3, 2025, p. 6.

[BEGIN CONFIDENTIAL]
[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[END CONFIDENTIAL]

Staff finds that the Company has made defensible choices, although specific assumptions may always remain controversial. While assumptions could be improved, there is not sufficient cause to not acknowledge the IRP. Regarding gas, Staff notes that the preferred portfolio only builds 300 MW of CCCT, with the rest being gas conversions and reciprocating engines, about which no concerns regarding cost assumptions have been raised.[41] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[43]

Regarding renewables, Staff notes that while some databases may show lower prices, this does not consider the expiration of tax credits, which are likely to be passed onto utilities and consumers in form of up to 30 percent higher costs for the acquisition of

38 CONF Idaho Power Response to RNW Information Request 2, Attachment 1.
39 NREL, Electricity Annual Technology Baseline (ATB) Data, 2024.
40 Lazard, Levelized Cost of Energy, 2024.
41 Idaho Power Response to RNW Information Request 7, Attachment 1.
42 Idaho Power CONF Response to RNW Information Request 2, Attachment 1.
43 Idaho Power CONF Response to RNW Information Request 2, Attachment 1.

new resources. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[44] Staff believes the assumptions for wind should be revisited in the next IRP as is further addressed in Recommendation 5. Lastly, Staff notes that the Company's Action Plan only contemplates all source RFPs, which means all resource types will be able to be compared using actual bid prices.

Staff appreciates Joint Stakeholder's independent research on resource costs and suggests that public input meetings are the right place to further discuss these issues. Staff expects the Company to dedicate a future input meeting to the selection of input assumptions for supply-side resources.

Gas Risk and Portfolio Diversity

Joint Stakeholders argue that the Company has insufficiently considered potential disruptions of the gas fuel supply or an extreme escalations of prices. Joint Stakeholders find the portfolio too reliant on gas with the addition of 1,161 MW of gas over the planning horizon. They note that the Preferred Portfolio costs an additional $3.2 billion in a high gas price scenario.

The Company disagrees with Joint Stakeholders and argues its portfolio diversifies risk by relying on natural gas and various renewable technologies. In Reply Comments, the Company explains that it is actively expanding to procure gas from three hubs via multiple pipelines, with SWIP-N creating energy alternatives for responding to events that might disrupt gas options in the Pacific Northwest. Furthermore, "the results of the stochastic analysis show that a non-diverse portfolio like the "No New Gas" portfolio performs substantially worse than the Preferred Portfolio when accounting for gas price volatility."[45] This is correct.[46]

While the Company's stochastic risk analysis supports the inclusion of gas investment in the Company's investment strategy, Staff agrees with Joint Stakeholders that the IRP would "benefit from a scorecard that summarizes portfolio performance across key quantitative (cost, emissions, dispatch), qualitative (regulatory risk, emerging

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44 Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Round 2 Comments, November 3, 2025, p. 3.
45 Docket No. LC 87, Idaho Power Company Reply Comments, October 6, 2025, p. 16.
46 The ninety-fifth percentile of PVRR in the stochastic analysis is $12.80 billion and $13.75 billion for the Preferred Portfolio and the No New Gas portfolio respectively. *See* Idaho Power Reply to OPUC Information Request 13, Attachment 1.

technology), and composite metrics (resource diversity, market reliance)."[47] Staff finds the Company's analysis and/or description lacking in several aspects. It is unfortunate that the Company does not compare alternative portfolio build outs such as "No New Gas" under different conditions, such as the "High Gas High Carbon Price" sensitivity. This would have provided the relevant comparison to address gas price risk. While the Company is correct that this is partly covered by the stochastic analysis, the graphs provided in the IRP do not clearly show this conclusion, and Staff had to request the underlying data to confirm this. It would be preferable, as Joint Stakeholders suggest, if the Company provided stochastically-derived metrics such as median PVRR or ninety-fifth percentile PVRR, which is already required by IRP Guideline 1c.[48] Furthermore, one of the functions of stochastic analysis should be to identify ranges of variable that would necessitate a substantively different portfolio. For instance, the analysis should answer the question under what gas prices the Preferred Portfolio is not least cost anymore. Another important feature would be to clearly explain how the Company arrived at the qualitative risk analysis and what the conclusions are. While Table 10.5 of the IRP shows a comparison of the qualitative analysis used to justify the Preferred Portfolio selection, the Company should make clear why its interpretation of those results supports its selection, and provide quantitative metrics such as those referenced above, to inform understanding of the tradeoffs it is considering.

Recommendation 4: In future IRPs, the Company should engage stakeholders on how it can improve its portfolio analysis and selection, including : 1) Better leveraging stochastic analysis to provide a discrete comparison of how candidate portfolios perform under the variation of individual variables (e.g., gas prices) and identify trigger points that would lead the Company to adopt a substantively different portfolio (e.g., if gas prices were to exceed x$ over 5 years); 2) providing stochastically-derived metrics to compare different portfolio buildouts; 3) connect the qualitative analysis more clearly to the resulting choices.

Wyoming Wind

Joint Stakeholders criticize the Company for only including one wind proxy resource located in Idaho, while the 2023 IRP included a Wyoming wind resource. This is significant because the latter is generally more economical. The Company believes this issue to be unimportant due to the fact that all source RFPs allow bids from all resources from any location.

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47 Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Opening Comments, September 8, 2025, p. 10f.

48 IRP Guideline 1c provides that a plan "should include at a minimum, two measures of PVRR risk: one that measure the variability of costs and one that measures the severity of bad outcomes," Docket No. UM 1056, Order No. 07-047, Appendix A, February 9, 2007, p. 2.

Staff believes stakeholders raise a good point that should not be limited to wind resources. The Company is heavily investing in the buildout of new transmission resources, including B2H, SWIP-N, and Gateway West, for the specific reason that this allows access to a more diverse set of resources. The next IRP should better reflect this reality. This may require some modeling adjustments, since external transmission lines currently provide capacity through market purchases.

Staff Recommendation 5: In future IRPs, the Company should engage stakeholders on proxy resource locations and include proxies for any resource location that is reasonably available to the Company and where the proxy performs materially differently than the same proxy resource at a different location.

Jackalope Wind Project

After the filing of the 2025 IRP, Idaho Power announced its withdrawal from the Jackalope Wind project, which had been included in the Preferred Portfolio.[49] In conversations with Staff, the Company provided more detail on this decision. Due to permitting delays and uncertainty around federal land use policies regarding wind resources, the developer of the project pushed the planned commercial operation date (COD) beyond 2027. While there is a possibility that the Jackalope Wind project will eventually be built, Idaho Power was relying on the 2027 COD to accommodate capacity deficits and therefore entered into a Letter Agreement to terminate the Build Transfer Agreement (BTA) and Power Purchase Agreement (PPA) associated with the project. Jackalope was estimated to have a relatively low Effective Load Carrying Capability (ELCC) of around 95 MW (16 percent). The Company is actively engaging with developers that submitted bids into the 2028 RFP to identify any projects that have the ability to accelerate their online date to address summer of 2027 capacity needs. For instance, Idaho Power was able to execute a PPA with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, a 2028 resource bid for which the developer agreed to an accelerated online date.

Staff has currently no concerns or questions regarding Jackalope Wind and looks forward to working with the Company on procurement efforts in RFP dockets.

QF Renewal Rates

In Idaho Power's 2023 IRP, Staff expressed concerns about the Company's assumption that zero percent of Public Utility Regulatory Policies Act (PURPA) wind qualifying facilities (QF) renew contracts at the end of their terms. In adopting Staff's

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49 Case No. IPC-E-25-28, Petition of Idaho Power Company to Withdraw Certificate No. 559, September 19, 2025.

recommendations 9 and 10, the Commission directed the Company to assume either a 75 percent renewal (or replacement) rate for all QFs or develop a forecast methodology based on historical data similar to that employed by PacifiCorp.[50] The Company addressed this recommendation by using historical renewal rates for biomass, cogeneration, hydro, and thermal while assuming a 75 percent renewal rate for wind and solar resources.[51]

In comments, REC explains that the Company's approach, while aligning with Commission direction, resulted in renewal assumptions that do not reflect Commission intent. REC states that, because of the inherent differences between PURPA laws in Oregon and Idaho regarding contract term lengths, the approach proposed by OPUC Staff in LC 84 unintentionally and dramatically minimizes assumed renewal rates over the planning horizon. Under Oregon's 20-year PPAs, assuming a 75 percent renewal rate for QFs over a 20-year planning horizon would, at most, apply to any QF once, reducing the total capacity of QFs by 25 percent by the end of the planning period. However, under Idaho's PURPA law, which only provides 2-year term PPAs going forward, applying a 75 percent rate reduces QF capacity by 86 percent instead of 25 percent over the planning horizon.

REC asserts that the application of a 75 percent rate every two years was improper and has various detrimental effects, including an underestimation of actual QF renewals, an overestimation of resource needs, unnecessary procurements, and the reduction of capacity payments to QFs, discouraging their continued operation. REC recommends the Commission decline to acknowledge QF planning assumptions for wind and solar. In addition, REC recommends the Commission direct the Company again to base QF planning assumptions on historical renewal rates or apply the 75 percent rate in a way that leads to a 25 percent reduction over the planning horizon.

Idaho Power disagrees with REC's assessment, stating that the Company believes it has implemented Commission direction appropriately. Furthermore, the Company explains that even if the assumed rate did not turn out to be accurate, the negative effects cited by REC would not automatically follow. First, the Company argues that it considers the most up-to-date information (not the IRP forecast) when assessing its capacity position for an RFP, ensuring that only necessary resources are procured. Second, the Company explains that renewing QFs remain eligible for the capacity payment determined in their original contract, meaning that IRP assumptions will not affect the capacity payment they receive. Lastly, the Company states that the capacity

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50 Docket No. LC 84, Order No. 24-285, Appendix A, August 26, 2024, p. 37.
51 Idaho Power Response to REC Information Request 3.

deficiency date analysis for new resources only counts contracted resources. Assuming higher renewal rates, as REC recommends, would actually lower capacity payments. After analysis, Staff does not believe QF renewal rates require remedial action by the Commission. For the resources besides wind and solar, the Company followed Commission direction by using historical data. For wind and solar in Oregon, the Company followed Commission direction by using a 75 percent renewal rate over the planning horizon. Staff agrees with REC that the result for wind and solar in Idaho is not in line with the Commission's intent and likely reflects that Staff recommendation 10 was incompletely contemplated on the part of Staff for application under Idaho's PURPA law. A QF renewal rate calculated to yield 75 percent of existing Year 1 QF capacity by Year 20, under Idaho PURPA law, would be approximately 95.97 percent.

Tracing the exact impact of reducing Idaho wind and solar QF capacity to under 14 percent of its starting capacity over the planning horizon is difficult without costly further analysis and additional consideration of forward electric market prices. However, regarding the impacts on the IRP Near-Term Action Plan, there is less concern on the part of Staff because the last action item for which the Company seeks acknowledgement is a procurement in the 2029-2030 timeframe. In this timeframe, the delta between forecasted QF generation and actual QF generation will not be as great, although it may still represent a roughly 20 percent under-forecast of existing QF power. Staff expects Idaho Power to base actual procurement based on updated QF renewal numbers, as stated by the Company.

Staff understands that the Company employs the Commission's Capacity Contribution Best Practices (Docket No. UM 2011), which call for including only resources that are contractually committed to come online during the study period for capacity contribution modeling.[52] Thus, the Company's potential over-forecast of future capacity need may ultimately increase the potential capacity contribution of new QF projects, with existing QF projects guaranteed the capacity contribution value offered in their initial contracts, under Idaho PURPA law, insulating those projects from potential impact. Therefore, Staff, in conjunction with the Company's commitment that it will evaluate existing resources at the time of the resource procurement, is comfortable at this time with this outcome, and does not support REC's recommendation to not acknowledge the QF renewal rates.

Staff considered whether the Commission should clarify its direction from Order No. 24-285 regarding QF renewal rates in Idaho. Staff consulted with Idaho Public Utility Commission Staff as to not give conflicting direction to Idaho Power. Idaho Public Utility Commission Staff recommends the following in its comments on the IRP:

[52] Docket No. UM 2011, Order No. 22-468, Appendix A, December 1, 2022.

1. Develop Oregon's rates and Idaho' s rates separately and use Idaho-specific data to develop Idaho' s PURPA new development and replacement rates;
2. Separately develop Idaho' s PURPA new development and replacement rates for projects that use the Surrogate Avoided Resource (SAR) method and for projects that use the Incremental Cost IRP (ICIRP) method; and
3. Contact the projects in Idaho that will expire soon to gain understanding of their project renewal intentions, when the empirical data for determining Idaho' s replacement rates is insufficient or not available.[53]

Oregon Staff is not opining on recommendations for the Company with regard to customers located in Idaho. However, Staff believes the intent of point three is similar to assuming a 75 percent renewal rate and sees practical value in deferring to Idaho Staff's recommendation. For Oregon, Staff finds the Company did comply with the intent of recommendations 9 and 10 from Order No. 24-285. Staff expects the Company to continue following these recommendations in future IRPs until a permanent policy is adopted in UM 2000.[54]

Large Loads

Large load additions are a major uncertainty not only for Idaho Power but also the industry as a whole. The Oregon Legislature recognized this with the passage of HB 3546 (2025), which requires electric utilities to adopt tariffs for retail customers with demand over 20 MW that assign all costs of service to that individual customer. The Commission is currently investigating large load tariffs for Portland General Electric[55] and PacifiCorp.[56] According to Idaho Power's tariffs in Oregon and Idaho, customers with demand exceeding 20 MW need to make special contract arrangements that mitigate cost shifting risks, although there are currently no such contracts for the Company's Oregon service territory.[57]

Idaho Power only includes large loads in its load forecast if there is high certainty that they will materialize:

> Seven out of nine total facilities expected to increase Energy Service Agreement ("ESA") load through 2030 have executed ESAs with Idaho Power. The two facilities that have not executed an ESA make up 69 aMW

53 Case No. IPC-E-25-23, Staff Comments, November 13, 2025.
54 Docket No. UM 2000.
55 Docket No. UM 2377.
56 Docket No. ADV 1790.
57 Idaho Power Company, Schedule 19.

> in 2030; however, these two facilities have executed construction agreements, procurement agreements, and/or generation studies.[58]

Joint Stakeholders are not convinced by the Company's approach:

> Hundreds of megawatts of over-procurement will occur under the Preferred Plan if just one or two large-load customers fail to materialize. In such a future, ratepayers will suffer increased rates while the Company enshrines near-term investments into 40-50 year (if not longer) thermal generation assets that may become uneconomic in the mid- to long-term.[59]

Joint Stakeholders recommend:

- The Company remove 265 MW of large load from its load forecast.
- The Company adopt a large load tariff that emphasize demand flexibility.
- The Commission open an investigation into the effects of large loads generally.

Staff believes, based on the information provided by the Company in this proceeding, that Idaho Power's load forecast is already relatively conservative. Furthermore, of the large loads expected by 2030, only 69 MW have not yet signed contracts designed to hold ratepayers harmless.[60] Staff also finds the Company's approach of carefully considering large load certainty in its RFPs (see Action Item 4) valuable. Overall, Staff sees no need for the Company to correct its load forecast in this RFP, although there would be value in showing a sensitivity with less than expected load in the next IRP.

Staff recently published its implementation plan for HB 3546 (2025) and currently recommends a utility-by-utility approach.[61] Given that Idaho Power does not expect any large loads in its Oregon service territory, monitoring the situation is the appropriate approach.[62] Staff notes that the Commission does not have any authority over tariffs for Idaho customers and that investments for Idaho customers are generally not recovered from Oregon ratepayers.

Recommendation 6: In future IRPs, the Company should include a sensitivity that explores the effects of some new large loads not materializing.

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58 Idaho Power Company Response to OPUC Information Request 7.
59 Docket No. LC 87, Northwest Energy Coalition and Renewable Northwest Opening Comments, September 8, 2025, p. 5.
60 Idaho Power Response to OPUC Information Request 7.
61 OPUC Staff, 2025 Legislative Implementation Plan, September 23, 2025.
62 Idaho Power Response to OPUC Information Request 7.

Gateway West Segment 8

Gateway West Segment 8 is a 128-mile, 500 kV line expected to increase transmission capacity on certain paths by 2,000 MW. Idaho Power is estimated to spend $762 million on this project. The Company expects to add Gateway West segment 8 to its portfolio in two phases, with one part online by 2028 and the rest online by 2030. Staff is uncertain why the Company has not included segment 8 in the IRP action plan, given that part of the line is expected to be online by 2028, which is within the action plan timeframe.

In its reply, the Company explained that its IRP does not analyze this segment since it is internal to the Idaho Power Balancing Area, which is modeled as one load bubble. Further, the Company states it "is advancing Segment 8 through routine transmission planning, permitting, and pre-construction activities since it is not a discrete resource action requiring acknowledgment, which the Action Plan solely focuses on."[63]

Staff believes that the IRP, as the main document explaining the Company's overall strategy, should include and justify any major transmission investments, even if they are internal to Idaho Powers Balancing Area and the Company is not seeking acknowledgment for them. The inclusion of all major costs is also being considered for performance metrics in the IRP/RFP modernization docket.[64]

Staff expects the Company to discuss all major transmission investments within the Action Plan window in future IRPs, even if no acknowledgment is sought.

B2H

The STOP B2H coalition is concerned about the treatment of B2H in the IRP as already committed resource under construction. STOP B2H believes that PacifiCorp's exclusion of B2H for its preferred portfolio in its 2025 IRP should lead to a reevaluation of the Certificate of Public Convenience and Necessity (CPCN) for the transmission line and cause Idaho Power to reconsider the economics of the transmission line.[65] STOP B2H recommends the Commission direct Idaho Power to either downsize B2H or forgo it completely in favor of enhancing existing transmission resources.

The Company replies that the issues raised largely pertain to a third-party and are outside the scope of its IRP analysis. Staff agrees. PacifiCorp's use of its ownership stake in B2H does not affect to degree to which this is a least-cost, least-risk resource for Idaho Power. Staff also notes that STOP B2H's claims regarding the CPCN have

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63 Docket No. LC 87, [Idaho Power Company Reply Comments](), October 6, 2025, p. 7.
64 Proposed OAR 860-090-0060(7)(g), Docket No. AR 669, [Staff Comments](), November 14, 2025.
65 Docket No. PCN 5, [Order No, 23-225](), June 29, 2023.

been rejected by the Commission in Order No. 25-456.[66] PacifiCorp's plan for B2H is currently under discussion in Docket No. LC 85.[67]

Conclusion

Staff finds that the IRP adheres to the procedural and substantive IRP Guidelines and that the IRP, represents a reasonable least cost, least risk plan based on the information currently available. Hence, Staff recommends the Commission acknowledge the IRP under the condition the Company provide a concrete plan regarding Bridger Units 3 and 4 in its next IRP. Based on various concerns raised, Staff recommends the Commission adopt the following five recommendations, which will improve analysis conducted in future IRPs and RFPs.

- **The Company's next RFP should include a summary of large load timing and probability (e.g., contract status, construction milestones, interconnection progress) and consider carbon-related regulatory risk quantitatively and qualitatively.**

- **The Company should bring a proposal to an IRP input meeting before the 2027 IRP for considering a DR RFP or better integrating DR into all source RFPs.**

- **In future IRPs, the Company should engage stakeholders on how it can improve its portfolio analysis and selection, including : 1) Better leveraging stochastic analysis to provide a discrete comparison of how candidate portfolios perform under the variation of individual variables (e.g., gas prices) and identify trigger points that would lead the Company to adopt a substantively different portfolio (e.g., if gas prices were to exceed x$ over 5 years); 2) providing stochastically-derived metrics to compare different portfolio buildouts; and 3) connect the qualitative analysis more clearly to the resulting choices.**

- **In future IRPs, the Company should engage stakeholders on proxy resource locations and include proxies for any resource location that is reasonably available to the Company and where the proxy performs materially differently than the same proxy resource at a different location.**

66 Docket No. UM 2394, Order No. 25-456, November 14, 2025.
67 Docket No. LC 85.

- **In future IRPs, the Company should include a sensitivity that explores the effects of some new large loads not materializing.**

Additionally, Staff memorializes expectations for future IRPs in Attachment 1.

PROPOSED COMMISSION MOTION:

Acknowledge Idaho Power's IRP with the condition the Company provide a concrete plan regarding Bridger Units 3 and 4 in its next IRP, including how coal will be removed from Oregon rates, and adopt the Staff recommendations set forth in the conclusion of this memo.

RA2 – LC 85

Attachment 1: Staff Expectations

In addition to recommendation to the Commission, Staff has outlined the following expectations for Idaho Power regarding the Company's next IRP:

1. The Company should evaluate candidate portfolios with and without major federal policy drivers (e.g., carbon policy) and explain how that analysis supports the selection of the preferred portfolio as well as near-term actions.
2. The Company should dedicate a future input meeting to the selection of input assumptions for supply-side resources.
3. In determining QF renewal rates for Oregon, the Company should continue following recommendations 9 and 10 from Order No. 24-285 unless new guidance is adopted in UM 2000.
4. The Company should discuss all major transmission investments within the Action Plan window, even if no acknowledgment is sought.