ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: July 30, 2024

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __________N/A__________

DATE: July 2, 2024

TO: Public Utility Commission

FROM: Abe Abdallah

THROUGH: JP Batmale and Kim Herb **SIGNED**

SUBJECT: IDAHO POWER:
(Docket No. LC 84)
Acknowledgement of the 2023 Integrated Resource Plan.

STAFF RECOMMENDATION:

Acknowledge Idaho Power Company's (Idaho Power, IPC, or the Company) 2023 Integrated Resource Plan (IRP, 2023 IRP), except for the Action Plan item that has already been substantially completed; approve Staff's recommendations for the 2025 IRP; and approve Staff's recommendation for granting the Company a waiver of the Company's obligation to file an update to the 2023 IRP.

Summary of Staff Recommendations on Action Plan Items

Below is a list of the Action Plan items presented by the Company in the 2023 IRP for acknowledgement[1] and Staff's associated recommendations. Dates in parentheses are taken from the Action Plan target year or range of years.

1. Continue exploring potential participation in the SWIP-North project. (2023–2024)
   Recommendation: Acknowledge

2. Explore a 5 MW long-duration storage pilot project. (2024–2028)
   Recommendation: Acknowledge

3. Install cost effective distribution-connected storage. (2025–2028)
   Recommendation: Acknowledge

4. Bring Boardman to Hemmingway (B2H) online. (Summer 2026)

[1] See Docket No. LC 78, Idaho Power, 2021 IRP, September 29, 2023, Table 1.3, p 9.

Recommendation: Not Acknowledge due to action item already executed

5. Convert Valmy units 1 and 2 from coal to natural gas. (Summer 2026)
   Recommendation: Acknowledge

6. If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources.(2026–2028)
   Recommendation: Acknowledge

7. Include 14 MW of capacity associated with WRAP. (2027)
   Recommendation: Acknowledge

8. Bring the first phase of GWW online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation). (2028)
   Recommendation: Acknowledge

DISCUSSION:

Issues:

1. Whether the Oregon Public Utility Commission (Commission) should acknowledge Idaho Power Company's 2023 IRP, acknowledge specific portions of the IRP with or without certain conditions, or decline to acknowledge the IRP.

2. Whether the Commission should approve Idaho Power's request for waiver of the Company's obligation to file an update to the 2023 IRP.

Applicable Rule or Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[2] 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), 08-339, and 12-013 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities for the Commission to consider acknowledgement of a utility's resource plan.[3] Also applicable to the review of Idaho Power's 2023 IRP is

[2] *See* Docket No. UM 180, OPUC, Order No. 89-507, April 20, 1989.
[3] *See* Docket No. UM 1056, OPUC, Order No. 07-002, January 8, 2007; See Docket No. UM 1056, OPUC, Order No. 07-047, February 9, 2007; Additional refinements to the process have been adopted: *See* Order No. 08-339 (Refining IRP Guideline 8 to specify how utilities should treat carbon dioxide

whether it complies with all of the Commission requirements in its previously acknowledged IRPs: LC 78 and LC 74.

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 acknowledgement order, or as otherwise directed by the Commission.[4] 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.[5] The ultimate goal of the IRP is to select the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[6] This is often referred to as the "least cost/least risk portfolio."

As the Commission states in Order No. 07-002: "[a]cknowledgement of the company's plan means only that we consider it reasonable at the time of our decision."[7] The Commission further states "[w]e 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."[8] The Commission has also declined to acknowledge specific Action Items when they are complete or substantially complete by the time the Commission issues its acknowledgement order.[9]

<u>Analysis</u>

Background
Idaho Power filed its 2023 IRP on September 29, 2023. The procedural schedule for this docket included two rounds of comments and a workshop attended by the Commissioners and Administrative Law Judge on October 31, 2023. Staff, the Renewable Energy Coalition (REC), and Renewable Northwest (RNW) filed Opening Comments on February 7, 2024. Idaho Power filed Reply Comments on March 7, 2024. Staff filed its Final Comments on April 25, 2024. The Company, REC, RNW, and the Citizens' Utility Board (CUB), engaged Staff's Final Comments with Reply Comments on May 23, 2024. The May 23, 2024, Reply Comments from the Company included a waiver request regarding requirements to file an IRP Update. REC filed supplemental comments on June 10, 2024. Staff thanks stakeholders for their engagement in this docket and the Company's willingness to engage with Staff and stakeholders on issues raised.

(CO2) risk in their IRP analysis); Order No. 12-013 (Adding guideline directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[4] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[5] *See* Docket No. LC 56, OPUC, Order No. 14-415, December 2, 2014, p. 3.
[6] *See* Docket No. UM 1056, OPUC, Order No. 07-002, January 8, 2007, pp. 1-2.
[7] Ibid. p. 16.
[8] Ibid. p. 1.
[9] *See* Docket No. LC 56, OPUC, Order No. 14-415, December 2, 2014, p. 7.

This report includes:

1. Discussion of the Action Items in the IRP Action Plan and related recommendations;
2. Additional issues raised by parties and related recommendations for the 2023 IRP;
3. Discussion on the waiver request filed by the Company regarding the IRP Update and related recommendation;
4. A summary of Staff's recommendations (Attachment 1); and
5. Staff's expectations for future IRPs, for which do not explicitly seek Commission direction (Attachment 2).

<u>Action Item Discussion</u>

Below are Idaho Power's 2023 IRP Action Plan items organized by the topics in which they are presented in this report.

Summary of Idaho Power 2023 Action Plan Items by Topic	
Topic	**Action Plan Item with Associated Action Item Number**
1 - Coal to Gas Conversion	Action Item 5: Convert Valmy units 1 and 2 from coal to natural gas by summer 2026.
2 - Wind and Solar Resources	Action Item 6: If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources in 2026 through 2028.
3 - Transmission	Action Item 8: Bring the first phase of Gateway West (GWW) online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation) by end-of-year 2028. Action Item 4: Bring B2H project online by summer 2026.
	Action Item 1: Continue exploring potential participation in the Southwest Intertie Project (SWIP)-North project in 2023-2024.
4 - Distribution-Connected Storage	Action Item 3: Install cost effective distribution-connected storage from 2025 through 2028.
5 - Long Duration Storage	Action Item 2: Explore a 5 MW long-duration storage pilot project between 2024 and 2028.

Summary of Idaho Power 2023 Action Plan Items by Topic	
Topic	**Action Plan Item with Associated Action Item Number**
6 - WRAP Benefits Modeling	Action Item 7: Include 14 MW of capacity associated with Western Resource Adequacy Program (WRAP) in 2027.

1. Coal to Gas Conversion

Idaho Power seeks acknowledgement of the conversion of Valmy units 1 and 2 from coal to natural gas in the Summer of 2026, presenting a case that the conversion of the North Valmy plant from coal- to gas-fueled generators is consistently selected by the Aurora Long-term Capacity Expansion (LTCE) model to best meet system needs in the lowest-cost manner. Staff and Stakeholders raised concerns about whether these conversions represented the least-cost option and whether alternatives were adequately considered. After receiving the Company's responses to Information Requests (IRs) by Staff and the Company's Final Reply Comments, Staff agrees that the conversion of Valmy 1 and 2 in 2026 provides the least-cost, least risk portfolio.

Based on the IRP and Company responses to IRs, Staff is convinced the converted gas units will operate more or less the same in terms of usage and deployment as the pre-conversion coal units. As described in Final Comments and in Attachment 2, Idaho Power should provide as part of the next IRP the following:

a) Evaluation of an alternative portfolio with delays in Valmy conversion to understand the implications and the need for a contingency plan to address it.
b) Workpapers for the projected number of hours for both baseload and peaking operation of the Valmy converted units in comparison with other types of resources. The data will help better understanding of the usage of Valmy units to fulfill system needs and the extent of total operating hours of the converted plant on emissions.
c) Evaluation of an alternative scenario for no coal to gas conversions in both Valmy units and Bridger Units 3 and 4 for a better understanding of emission implications of continued use of fossil fuel generation.
d) Inclusion of any cost estimates of significance for SO_2 and NO_X emissions related to the converted plant, in its advisory IRPAC meetings.
e) Investigation of any impacts of the recently introduced Environment Protection Agency (EPA) rules for Greenhouse Gas (GHG) emissions' Standards and Guidelines for Fossil Fuel-fired power plants on resource planning.

In response to Staff's Final Comments, both Idaho Power and RNW point to the recent PacifiCorp IRP Update filing that both Bridger Units 3 and 4 will no longer be converted to gas in 2030 and will rather be installed with carbon capture and sequestration (CCS) technology and continue operating on coal.[10] RNW would like the Company to provide an update on this development at the Special Public Meeting of this IRP.[11] The Company commented that the continuation of Bridger Units 3 and 4 will negate the need to do scenario analysis of exiting coal plants by 2030 and suggested the Company conduct a full evaluation of various practical options of converting, exiting, or modifying Bridger Units 3 and 4 in the 2025 IRP.[12]

Staff agrees with RNW that the Company should update the Commission with the development on the future of Bridger Units 3 and 4 and the impact on resource planning in the next IRP. Although the operation of the coal plant is unlikely to change from including the CCS technology, Staff would like to the see the Company conduct comprehensive studies in the 2025 IRP on the details of Bridger Units 3 and 4 and the implications on the resource build in the preferred portfolio selection. Staff is interested in the evaluation of the cost of the retrofitted plant with the CCS technology, the impact on the near-term action plan, and the resulting emission reduction in the 20-year planning period.

In response to Staff's Final Comments,[13] CUB seeks additional information behind Staff's draft recommendation to acknowledge the Valmy conversions. Similarly, RNW wrote that it "would be difficult to acknowledge the Valmy conversions based on the current record…" but did not provide further detail about their concern.[14]

Staff appreciates this request and provides further detail supporting its recommendation for acknowledgement of the Valmy conversions below. In recommending acknowledgement of the Valmy units' conversion, Staff discusses some key topics:

- NVPRR Cost Comparisons: comparison of costs of portfolios "with Valmy" and "without Valmy" and discuss the cost drivers.
- Model Assumptions: Validation of gas price and operational characteristics of the Valmy conversion that are input into the model.
- Capacity Length: The need for the Valmy conversions.
- Demand Side Management (DSM) Alternatives: Energy Efficiency (EE) and Demand Response (DR) as alternatives to Valmy conversions.
- Contingency plans: Evaluation of costs and risks from failure to materialize or stranded assets.

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[10] *See* Docket LC No. LC 82, PacifiCorp's 2023 Integrated Resource Plan Update, April 1, 2024, p. 14.
[11] *See* Docket No. LC 84, RNW's Final Comments, May 23, 2024, p. 3.
[12] *See* Docket No. LC 84, Idaho Power Company's Final Reply Comments, May 23, 2024, p. 7.
[13] *See* Docket No. LC 84, CUB's Final Comments, May 23, 2024, pp. 2-3.
[14] *See* Docket No. LC 84, RNW's Final Comments, May 23, 2024, p. 2.

- Exit Fees for Valmy 1: Impact on customer rates from IPC's re-participation in Valmy unit 1.

NPVRR Cost Comparisons
Portfolio analysis in the 2023 IRP shows that the Net Present Value Revenue Requirement (NPVRR) for the Preferred Portfolio, which includes both gas-converted Valmy units and B2H online in July 2026, is $9,746M.[15] The cost for the equivalent portfolio without Valmy is $9,824M.[16] The difference between these two costs is $78M.

Further, on April 19, 2024, IPC provided an update on the timing of B2H, indicating that a July 2026 in service date was no longer possible. [17] Given this, Staff instead looked at the portfolios with B2H in-service date of November 2026, where the difference between the portfolios climbs to $425M.[18]

Figure 1 shows the comparison of portfolio costs for the "With Valmy 1 and 2" and "Without Valmy" for both the B2H online in July 2026 and B2H online in November 2026. Allowing the model to select the Valmy conversions provides more than five times the savings in the delayed B2H in-service date of November 2026, as compared to the originally planned B2H in-service date in July 2026. The Company claims that the high savings in portfolio cost of $425M is a reflection of how Idaho Power's relies on the Valmy conversions to help mitigate the risk of an anticipated delayed B2H in-service date beyond July 2026.[19]

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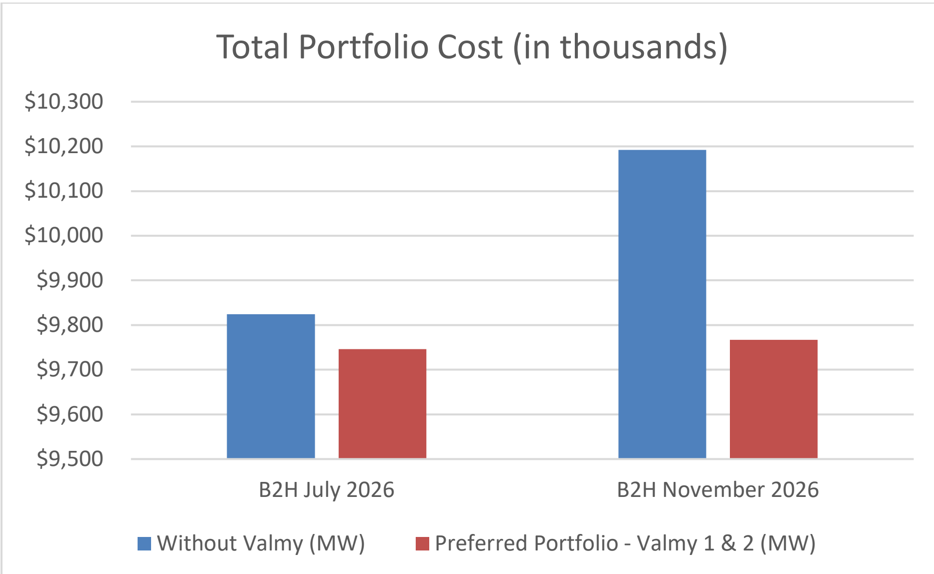
[15] *See* Docket No. LC 84, Idaho Power, 2023 IRP-Appendix C, September 29, 2023, p. 42.
[16] *Ibid*, p. 44.
[17] *See* Docket No. LC 84, Idaho Power, Idaho Power's 2023 Integrated Resource Plan: Update on Boardman to Hemingway Timing, April 19, 2024.
[18] *See* Docket No. LC 84, Idaho Power, 2023 IRP-Appendix C, September 29, 2023, p. 45 and p. 47.
[19] *See* Docket No. LC 84, Idaho Power Company's Reply Comments, May 23, 2024, p. 21.

Figure 1: Comparison of Portfolio Costs (in thousands)



Staff prefers to use the B2H November 2026 online case to investigate the drivers for the cost difference from the “Valmy 1 and 2” portfolio, as shown in Figure 2, and the “Without Valmy” portfolio, as shown in Figure 3. Staff chose the case of B2H online in November 2026, as the B2H online in July 2026 is no longer possible.

Figure 2: Nov2026 B2H Without Valmy (MW) Portfolio[20]

November 2026 B2H Without Valmy (MW)

Year	Coal Exits	Gas Exits	New Gas	H2	Wind	Solar	4-Hr	8-Hr	100-Hr	Trans.	Geo	Demand Response	Energy Efficiency Forecast	Energy Efficiency Bundles
2024	-357	0	357	0	0	100	96	0	0	0	0	0	17	0
2025	0	0	0	0	0	200	227	0	0	0	0	0	18	0
2026	-134	0	0	0	0	400	100	300	0	Nov B2H	0	40	19	27
2027	0	0	0	0	400	375	5	0	0	0	0	0	20	0
2028	0	0	0	0	100	150	5	0	0	0	0	0	21	0
2029	0	0	0	0	400	200	5	0	0	GWW1	0	20	22	0
2030	-350	0	350	0	400	0	0	0	0	0	30	0	21	0
2031	0	0	0	0	400	100	5	0	0	GWW2	0	0	21	0
2032	0	0	0	0	100	400	205	0	0	0	0	0	20	0
2033	0	0	0	0	0	0	105	0	0	0	0	0	20	0
2034	0	0	0	0	0	0	55	0	0	0	0	40	19	0
2035	0	0	0	0	0	0	5	0	0	0	0	40	18	0
2036	0	0	0	0	0	0	5	0	0	0	0	40	17	0
2037	0	0	340	0	0	0	0	0	0	0	0	0	17	0
2038	0	-706	0	340	0	0	5	0	100	0	0	0	17	0
2039	0	0	0	0	0	0	0	0	50	0	0	0	15	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	14	0
2041	0	0	0	0	0	600	0	0	0	GWW3	0	0	14	0
2042	0	0	0	0	0	300	5	0	0	0	0	0	14	0
2043	0	0	0	0	0	500	5	0	0	0	0	0	14	0
Subtotal	-841	-706	1,046	340	1,800	3,325	833	300	150		30	180	360	27
Total	**6,844**	**Portfolio Cost: $10,192M**												

[20] *See* Docket No. LC 84, Idaho Power, 2023 IRP-Appendix C, September 29, 2023, p. 47.

Figure 3: Nov2026 B2H Valmy 1 & 2 (MW) Portfolio[21]

November 2026 B2H Valmy 1 & 2 (MW)

Year	Coal Exits	Gas Exits	New Gas	H2	Wind	Solar	4-Hr	8-Hr	100-Hr	Trans.	Demand Response	Energy Efficiency Forecast
2024	-357	0	357	0	0	100	96	0	0	0	0	17
2025	0	0	0	0	0	200	227	0	0	0	0	18
2026	-134	0	261	0	0	400	155	0	0	Nov B2H	40	19
2027	0	0	0	0	400	375	5	0	0	0	0	20
2028	0	0	0	0	100	150	5	0	0	0	0	21
2029	0	0	0	0	400	200	5	0	0	GWW1	0	22
2030	-350	0	350	0	400	0	5	0	0	0	0	21
2031	0	0	0	0	400	500	55	0	0	GWW2	0	21
2032	0	0	0	0	100	0	5	0	0	0	20	20
2033	0	0	0	0	0	0	55	0	0	0	40	20
2034	0	0	0	0	0	0	55	0	0	0	40	19
2035	0	0	0	0	0	0	55	0	0	0	0	18
2036	0	0	0	0	0	0	5	50	0	0	0	17
2037	0	0	170	0	0	0	5	50	0	0	0	17
2038	0	-706	0	340	0	0	55	0	200	0	20	17
2039	0	0	0	0	0	0	50	0	0	0	20	15
2040	0	0	0	0	0	0	5	50	0	0	0	14
2041	0	0	0	0	0	300	5	0	0	GWW3	0	14
2042	0	0	0	0	0	300	5	0	0	0	0	14
2043	0	0	0	0	0	300	55	0	0	0	0	14
Subtotal	-841	-706	1,137	340	1,800	2,825	908	150	200		180	360
Total	**6,353**	**Portfolio Cost: $9,767M**										

The net capacity position of "Valmy 1 and 2" portfolio is 491 MW less than the "Without Valmy" portfolio. Table 1 shows the difference in net capacity for the 20-year planning period for only the resources that are different between both portfolios. Notable differences for the "Valmy 1 and 2" portfolio are the overall lower capacity in solar resources and the lack of geothermal resources.

Table 1: Portfolio Capacity Comparison

Portfolio Capacity	Total	New Gas	Solar	4Hr	8Hr	100Hr	Geo	EE Bundles
Nov2026 B2H Without Valmy (MW)	**6844**	1046	3325	833	300	150	30	27
Nov2026 B2H Valmy 1 & 2 (MW)	**6353**	1137	2825	908	150	200	0	0
Difference (MW)	**491**	-91	500	-75	150	-50	30	27

[21] *See* Docket No. LC 84, Idaho Power, 2023 IRP-Appendix C, September 29, 2023, p. 45.

To understand how the selected resources impacted the NVPRR of each portfolio, the energy output for each type of resource over the planning period needs to be considered. Table 2 shows the total output MWh for each resource category over the 20-year period to meet the forecasted load.[22]

Table 2: Energy Output by Resource Type (MWh)

Energy Summary	Nov2026 B2H Without Valmy	Nov2026 B2H Valmy 1 & 2	Difference (MWh)
Hydro	146,795,359	147,370,101	(574,741)
Coal	8,803,667	9,044,900	(241,233)
Gas	42,145,712	46,131,033	(3,985,321)
H2	378,160	418,830	(40,670)
PURPA	86,447,920	86,447,920	-
New Solar	44,162,256	39,335,595	4,826,661
New Wind	94,527,790	94,081,453	446,337
New Storage	(6,105,200)	(5,301,099)	(804,101)
Other	7,892,339	1,178	7,891,161
Nuclear	-	-	-
DR	1,602,974	1,620,719	(17,745)
Market Purchases	67,592,339	70,832,689	(3,240,350)
Market Sales	(20,248,725)	(15,988,726)	(4,259,999)

It is evident from Table 2 that the two portfolios differ significantly in the output energy of three types of resources: gas, new solar, and “other” resources. From the workpapers provided by IPC, Staff found that the output of “other” resources is almost entirely geothermal energy, and the remainder of 0.01 percent is diesel energy.[23]

Staff compared the levelized cost of energy of these three resources to get a rough idea of the cost drivers of the entire portfolio, as shown in Table 3.[24]

[22] Table reproduced from Docket No. LC 48, IPC’s response to Staff IR 7, Attachment 15, “Energy Summary” tab.
[23] *See* Docket No. LC 48, IPC’s response to Staff IR 7, Attachment 15, “Energy Summary” tab.
[24] Table reproduced from Docket No. LC 84, Idaho Power 2023 IRP, September 29, 2023, Table 8.4, p. 116.

Table 3: Levelized cost of energy (LCOE) of supply-side resources

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Total Cost per MWh	Capacity Factor
Clean Peaking Gas - Hydrogen Combustion Turbine	$ 68	$ 50	$ 191	$ 309	12%
Danskin 1 Retrofit - SCCT to CCCT Conversion	$ 56	$ 13	$ 46	$ 115	55%
Baseload Gas - Combined Cycle Combustion Turbine (CCCT)	$ 36	$ 12	$ 42	$ 89	55%
Peaking Gas - Simple Cycle Combustion Turbine (SCCT)	$ 98	$ 50	$ 66	$ 214	12%
Nuclear - Small Modular Reactor	$ 83	$ 42	$ 13	$ 139	94%
Geothermal	$ 50	$ 27	$ -	$ 78	90%
Biomass	$ 65	$ 61	$ 110	$ 236	64%
Solar PV	$ 17	$ 15	$ -	$ 31	31%
Wind - WY	$ 16	$ 19	$ -	$ 35	47%
Wind - ID	$ 28	$ 25	$ -	$ 53	36%
Short Duration Storage - Li Battery (4 hour)	$ 97	$ 37	$ -	$ 134	17%
Short Duration Storage - Li Battery (4 hour) - Grid Distributed	$ 88	$ 36	$ -	$ 124	17%
Medium Duration Storage - Li Battery (8 hour)	$ 77	$ 33	$ -	$ 111	33%
Long Duration Storage - Pumped Hydro (12 hour)	$ 82	$ 17	$ -	$ 99	50%
Multi-Day Storage - Iron Oxide Battery (100 hour)	$ 148	$ 36	$ -	$ 184	15%

Table 2 shows the energy produced with the consumption of gas in the “Without Valmy” portfolio is lower than Solar and Geothermal energy. Assuming the LCOE for the converted Valmy units is closer to baseload gas than peaking gas, the running of less gas at a cost of $89/MWh and more solar at $31/MWh, will still be less than the cost of the large output of geothermal energy at a cost of $78/MWh, as per the LCOE in Table 3. This means that the “Without Valmy” portfolio results in an increased energy output of almost 7,900 MWh with an associated increase of $425M for the portfolio.

The Company further explains that the Valmy conversions serve as a mitigation measure for a B2H delay. IPC’s access to the Four Corners market beyond the 2026 – 2027 winter season come via the swapped transmission capacity from PacifiCorp, which is contingent upon B2H being in-service.[25] Staff deduces that not having Valmy available, coupled with no access to markets, results in reliance on more expensive resources to run.

Staff sought to understand the near-term cost impacts of portfolio selection for the Valmy test cases. Table 4 shows the portfolio cost for the first five years of the planning period.[26]

[25] See Docket No. LC 48, IPC’s response to Staff IR 88.
[26] Table reproduced from Docket No. LC 48, IPC’s response to Staff IR 7, Attachment 15, “Portfolio Cost” tab.

Table 4: Near-term cost of portfolios by year

Portfolio Cost	Nov2026 B2H Without Valmy	Nov2026 B2H Valmy 1 & 2	Difference (MWh)
2024	$610,440	$608,378	$2,061
2025	$626,539	$627,099	-$560
2026	$686,524	$623,728	$62,795
2027	$896,982	$852,523	$44,459
2028	$923,976	$881,658	$42,318
Total	**$3,744,460**	**$3,593,387**	**$151,074**

Table 4 captures how the inclusion of Valmy units saves $151M. This cost saving in the first five years can be attributed to the "Without Valmy" portfolio having to run more expensive resources than the Valmy units to meet the load growth anticipated in 2026-2028.[27] In conclusion, the absence of other resources available to the model to meet the high-load growth, Valmy Units 1 and 2 appears to be the least cost option in the near-term.

Model Assumptions

Staff's aim is to ensure that the inputs to the model for the converted Valmy units are reasonable and do not induce the model to select the Valmy units over other resources. Staff looked at two key inputs to the model, natural gas prices and operational characteristics for the converted plant.

Gas prices

In the 2023 IRP, Idaho Power uses the natural gas price forecast from Platts, a third-party vendor for base planning.[28] Platts uses the Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington, for existing and potential new natural gas generation. Idaho Power states in the 2023 IRP that it also relies on alternative forecasts from the U.S. Energy Information Administration (EIA) for sensitivity analysis regarding the impact of high and low gas prices.[29]

Staff checked the consistency of gas prices input to the model for all resources and can confirm that the same forecast gas prices have been applied to existing and proxy gas prices for the 20-year planning period.[30] As such, Staff does not see that coal-to-gas

[27] See the load forecast of ESA customers in Table 6.
[28] See Docket No. LC 84, Idaho Power, 2021 IRP, September 29, 2023, pp. 110-111.
[29] See Docket No. LC 84, Idaho Power, 2021 IRP, September 29, 2023, p. 111.
[30] See Docket No. LC 48, IPC's Confidential response to Staff IRs 14 and 15.

converted Valmy units are treated any different in the model from other resources using natural gas as fuel.

Operational Characteristics
Idaho Power confirmed that the unit characteristics and deployment of the Valmy units converted to gas will be similar to the same units' pre-conversion under coal operations.[31] In its reply comments, the Company claimed that the converted Valmy units will be expected to serve a variety of purposes, both as baseload and peaking plant, citing the Aurora model consistently selecting the Valmy converted units.[32]

Per Staff's request, the Company provided tables of historical data for capacity factor and capacity contribution of the Valmy units from 2013-2022.[33] The Company also provided the annual capacity factors and the capacity contribution modeled in Aurora for the IRP 20-year planning period.[34] Staff found that capacity factors for the coal plant were very similar to the post-conversion gas plant. However, in most of the years in the 20-year planning period, the capacity factor values of the converted units conservatively resemble the low end of capacity factor values for the pre-conversion coal units, ranging from 9 to 10 percent in 2015 to 2017.

Based on the data provided by the Company on the fuel prices and operational characteristics of the gas-converted Valmy units, Staff does not see anything unreasonable with assumptions for the modeled coal-to-gas converted Valmy units.

Capacity Length
In the 2023 IRP, Idaho Power showed that base case portfolios 1) with both Valmy units, 2) with only Valmy 2, and 3) without Valmy units were all in a position of capacity length for every year of the 20-year planning period.[35] Staff noted that the portfolio without Valmy Conversions did not show a capacity shortfall, and questioned whether the Valmy conversion was a critical resource.

IPC explained that the capacity length of all base case portfolios over the 20 years planning horizon meant that these portfolios exceeded the Company's Loss of Load Expectation (LOLE) reliability threshold. The Company claimed that because selectable resource size, capacity contribution, and timing vary by resource type, it is normal to expect various years to show greater capacity length than others.

[31] See Docket No. LC 48, IPC's response to Staff IR 39.
[32] See Docket No. LC 48, Idaho Power Final Reply Comments, May 23, 2024, pp.5-6.
[33] See Docket No. LC 48, IPC's response to Staff IR 132.
[34] See Docket No. LC 48, IPC's response to Staff IR 133.
[35] *See* Docket No. LC 84, IPC response to Staff's OPUC IR No. 115, Attachment 1.

Staff considers IPC's explanation on capacity position reasonable. Capacity length does not necessarily indicate that a particular resource is not needed, but rather it is relative cost of running different resources.

Demand Side Management (DSM) alternatives to Valmy conversions

In opening comments, Staff asked about why additional EE and DR resources were not considered as alternatives to Valmy conversion. Staff noted that there was a decline in the amount of EE resources from 440 MW to 360 MW between the 2021 and 2023 IRPs. Staff also noted a projected growth rate of 9 percent for Energy Service Agreements (ESA) customers. Therefore, Staff asked if the capacity need stemming from this customer group could be addressed by targeted DSM, and if that could remove the need for Valmy conversion.

In its reply comments, the Company explained that it does not develop targeted DSM measures with individual customers. Rather, it uses a potential study to determine possible future measures it could offer to customers.[36] Further, the Company explained that additional EE and DR were available for selection in the Aurora model, but that the model chose the lower cost Valmy conversion.[37] When the model did not have Valmy units available, both additional EE and DR were selected, as shown in the resource build in Figure 2 for the “November 2026 B2H Without Valmy” portfolio. However, this portfolio is much more expensive than the “November 2026 B2H With Valmy 1 and 2” portfolio.

With regards to EE measures for ESA customers, the Company explained that energy-cost savings are foundational to ESA customers and that Idaho Power receives a load forecast from each ESA customer on a biannual to annual basis. These load forecasts inherently include EE measures planned for their facility and should encompass any changes in EE measures throughout the EE planning period.[38]

Staff understands that the additional EE and DR quantities were selected in the portfolios without Valmy units being available. However, these quantities were not enough to replace the 216 MW capacity of the converted Valmy units. Staff understands from discussions with the Company that the model selects DR or EE bundles based on costs, as well as the immediate availability of the bundle or the suitability of the shape of the bundle to meet the demand at the time it is needed.

Staff acknowledges that there could still be EE potential from large load customers that the Company could be missing. The Company informed Staff that in Idaho, where these

[36] *See* LC 84, IPC’s Reply Comments, March 7, 2024, p. 21.
[37] *Ibid*, p. 22.
[38] *See* Docket No. LC 48, IPC’s response to Staff IRs 121, 122 and 113.

ESA customers are located, there is no law incentivizing large-load customers to optimize their EE programs. Other concerns regarding EE avoided cost methodologies are discussed later in the Energy Efficiency section in this report.

Contingency plans
Staff had concerns about risk considerations beyond what was included in the IRP analysis. In its Opening Comments, Staff asked that IPC discuss its evaluation of cost and risks for customers in the event the Valmy conversion does not materialize or if the converted plants become stranded assets. Staff also pointed out that response to Staff's IR 47 revealed that Idaho power had not signed a contract with the co-owner NV Energy.

In its reply to Staff's Opening Comments, the Company asserts that the Valmy conversions have a significantly higher certainty, compared to other yet-to-be-built resources, and sees a low risk of delay from the planned online date in 2026. The Company states that the Bridger Units 1 and 2 conversion projects that are currently underway inform assumptions about the type of new equipment required and the associated costs and timeline for converting the Valmy units. In addition, the permitting process is expected to be similar to the Bridger conversions, and the construction of a gas lateral from an existing gas pipeline is relatively straightforward.[39]

In response to Staff's inquiry about the risk of Valmy ending up being a stranded asset, the Company replied that it would update IRP portfolio analysis if Valmy becomes uneconomic, then apply for rate recovery prior to end of life.[40]

Staff finds most of the explanations provided by the Company to be reasonable. The recent acknowledgement by Public Utility Commission of Nevada for the Valmy plant conversion partly addresses the uncertainty in contracting with NV Energy.[41] However, Staff still expects a delayed conversion scenario in future analysis. A discussion on this expectation by Staff is discussed in Attachment 2.

Exit Fees for Valmy 1
Staff was concerned about the potential impact on customer rates from the Company's reversal from paying exit fees since exiting participation in Valmy 1 in 2019 and what re-participation would imply. In response to Staff's IR 119, IPC explained that the Company is obligated to pay fees associated with the exit from participation in operation of Unit 1, according to the framework agreement between co-owner NV Energy and

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[39] *See* Docket No. LC 48, IPC's Reply Comments, March 7, 2024, p. 19.
[40] See Docket No. LC 48, IPC's response to Staff IR 117.
[41] NewsData, PUCN Approval of NV Energy IRP Amendments Eliminates Coal by Late 2025, Mar 8, 2024, accessed on June, 26, 2024.

Idaho Power. Staff discovered, upon further research, that paying the exit fees is a net benefit to customers, as the operation and maintenance costs that Idaho Power was able to avoid by exiting exceeded the exit fees it was obligated to pay under the framework agreement.[42]

Recommendation 1: Acknowledge Action Item 5: Convert Valmy units 1 and 2 from coal to natural gas by summer 2026.

2. Wind and Solar Resources

Idaho Power's action item to acquire up to 1,425 MW of combined wind and solar, if economic, is derived from unprecedented large and rapid load growth. However, the Company's preferred portfolio shows capacity length due to the inclusion of the Valmy conversions, and the lack of history supporting new load growth makes it challenging to confirm the predicted timing of the need. While Staff supports this action item, it notes that procurement efforts should be right sized and thoughtfully timed to minimize costs to customers.

Idaho Power seeks acknowledgement of acquiring up to 1,425 MW of combined wind and solar in 2026-2028, if economic, to meet resource needs identified in the preferred portfolio. This is up from 1,285 MW in the last IRP.[43] The Company supports this need with modeling that shows a 44 MW capacity deficit in 2027 and an additional, incremental deficit of 138 MW in 2028.[44] Further, using the 70th percentile probability, which Staff discusses in more detail in Section 8 - Load Forecast, it forecasts an average annual 2.1 percent growth rate of energy demand and an average 1.8 percent annual growth rate in peak hour demand, during the 20-year planning period.

However, the near-term annual average load growth between 2024 and 2028 is especially steep at 5.5 percent and is heavily weighted by additional firm sales to ESA customers, as shown in Figure 4.[45]

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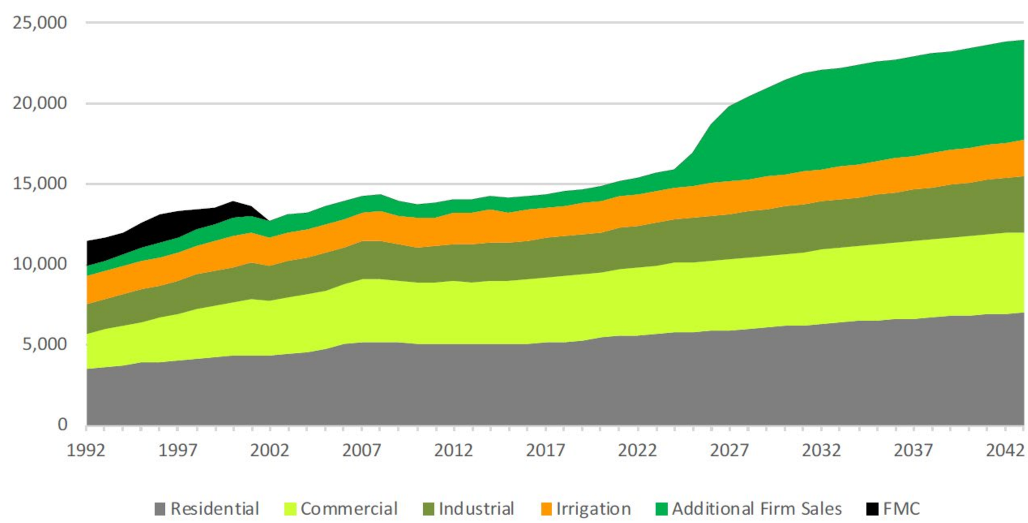
[42] *See In the Matter of IDAHO POWER COMPANY Application for Authority to Decrease Rates for Electric Service for Costs Associated with the North Valmy Power Plant*, Docket No. UE 363, Order No. 19-341, App. A, p. 4 (October 15, 2019) (Approving Stipulation regarding Idaho Power Company's Application for Approval or Acknowledgement of Framework Agreement with NV Energy in which parties agreed "The newly-structured payment obligations contained in the Framework Agreement provide a financial benefit to customers because (a) incremental capital improvements associated with an exited unit cease; (b) common facility costs are reduced as a result of Idaho Power's new capacity share; and (c) future variable operating costs associated with an exited unit would not be incurred.").

[43] In Docket No. LC 78, Idaho Power, 2021 IRP, September 29, 2023, Table 11.2, p 152, the preferred portfolio included 700 MW of wind in 2024 and 585 MW from 2026 to 2028.

[44] In Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 174, Table 11.15 shows additional capacity need of in 2026, 44 MW in 2027, and 182 MW in 2028, totaling 248 MW.

[45] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 100.

Figure 4: Composition of System Company Electricity Sales (thousands of MWh)[46]



Staff and stakeholders commented on procurement volumes and timing; system reliability and resilience; and procurement planning.

Timing and Volume

Approximated Volume

In both its opening and final comments, RNW suggested that Action Item 6 should be modified to accommodate a more flexible procurement target by replacing the acquisition of "**up to** 1,425 MW of …" with the acquisition of "**approximately** 1,425 MW or more …." combined wind and solar, or other economic resources.[47] RNW makes this recommendation for a higher volume of resources in excess of expected contracting levels to allow for negotiations in an uncertain procurement environment. RNW adds that ultimately the possibility of higher procurement volumes can be addressed in the relevant RFP dockets and rate-recovery proceedings.

Staff understands RNW's suggestion to allow for a more generous acknowledgement in the IRP docket and appreciates the flexibility it represents. However, Staff also appreciates the touchstone of volumes identified as part of a stakeholder-vetted IRP process. As Staff proposed in its Final Report on Idaho Power's 2026 All-Source RFP, the Company should use its best judgement when selecting a final procurement volume

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[46] *See* Docket No. LC 84, Idaho Power, 2023 IRP-Appendix A, September 29, 2023, Figure 3, p. 12.

[47] *See* Docket No. LC 84, RNW's Opening Comments, Feb. 7, 2024, p. 2; RNW's Final Comments, May 23, 2024, p. 2.

from the RFP.[48] If the company decides to pursue a higher volume of projects in the course of an RFP, any such procurement can be informed by a report by the Company detailing the reasons for such a decision.

Influence of ESA Customer Forecasts

The forecasted growth for ESA Customers represents a radical shift from past load forecasts, both in its scale and speed. This shift appears to be a primary driver of the timing and volume of the proposed near-term procurements.

Appendix A of the 2023 IRP identifies the forecast for average annual load growth for the key load classes of residential, commercial, industrial, irrigation and additional firm loads.[49] Focusing on the near-term, Staff summarized the average annual growth (aMW) and growth rate (%) for 2024-2028 in Table 5.

Table 5: Near-term average load growth by customer class (2024-2028)

Customer Class	2024	2028	aMW growth	% growth
Residential	678	708	30	4.4%
Commercial	500	515	15	3.0%
Industrial	311	326	15	4.8%
Irrigation	240	244	4	1.7%
Additional Firm	135	589	454	336.3%
Total	**3,888**	**4,410**	**522**	**13.4%**

Table 5 shows that the additional firm load has the highest growth rate by a significant margin. This customer class consists of Idaho Power's largest customers, or ESA customers (i.e. Special Contract Customers), who are served greater than 20 MW under a special contract. Table 6 shows significant annual growth in the near-term from 2024-2028.

[48] *See* Docket No. UM 2255, Idaho Power 2026 All Source Request for Proposals., February 1, 2024, p. 10.

[49] In Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix A, Tables 7-11, pp. 20-34. See Docket No. LC 84, Idaho Power, 2023 IRP, IPC response to IR 9, Appendix A: Attachment 2, Individual year figures.

Table 6: Average-energy load growth (aMW) 2024-2028 for ESA Customers

	Load (aMW)	y-on-y (aMW)	% growth
2024	135		
2025	225	90	40.0%
2026	423	198	46.8%
2027	539	116	21.5%
2028	589	50	8.5%
2024-2028	**454**		**336.3%**

Looking at the system peak hour MW forecast, Staff summarized the near-term peak load, which represents the summer peak load (MW) for 2024-2028 in Table 6.[50] Staff understands the 2028 summer peak to be a major driver of the timing of the procurement.

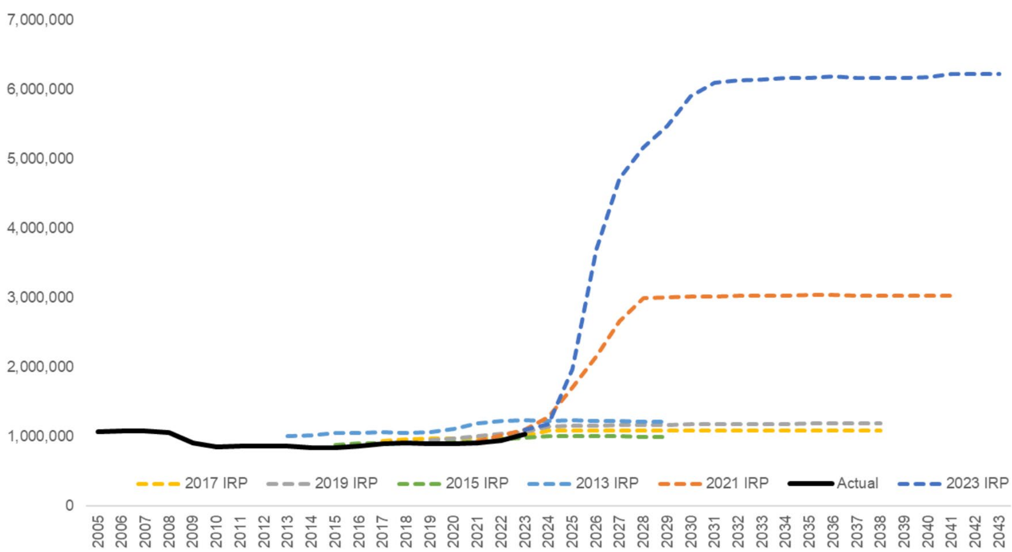
Table 7: System Peak Load (MW) (2024-2028)

Year	Load	y-on-y	% growth
2024	3,830		
2025	4,001	171	**4.4%**
2026	4,256	255	**6.3%**
2027	4,406	150	**3.5%**
2028	4,501	95	**2.1%**
2024-2028	671		**17.5%**

In Comments, Staff noted that the accuracy of Idaho Power's forecast of system load may become compromised if the near-term growth of ESA load does not materialize. Idaho Power is ultimately responsible for the reasonableness of these ESA customers' load forecast and should be prepared to provide oversight to avoid the over-procurement of resources. Figure 5 shows the difference in ESA customer load forecasts across IPC's past IRPs.

[50] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Table 8.2, p. 106, "70th Percentile load" column.

Figure 5: IRP Representation of ESA Customer Energy Load in MWh



Staff agrees that the Idaho Power system is experiencing growth and is supportive of the Company taking the necessary steps to meet these needs. However, Staff notes that this new growth introduces uncertainty regarding timing and volume of need. Given that the Company is currently developing its 2028 RFP (Docket No. UM 2317), Staff plans to address this issue in the RFP design and associated sensitivities.

Capacity Length – Valmy Conversions

Idaho Power presents its pre and post preferred portfolio annual capacity positions in Table 11.15 of the IRP, as shown in Figure 6.[51]

[51] See Docket No. LC 84 Idaho Power 2023 IRP, September 29, 2023, p. 174.

Figure 6: Pre and post Preferred Portfolio annual capacity positions

Annual Capacity Position (MW)				
Year	Existing & Contracted Resource Only		Add Preferred Portfolio Resources	
2024	11	Length	11	Length
2025	3	Length	3	Length
2026	(22)	Shortfall	224	Length
2027	(44)	Shortfall	284	Length
2028	(182)	Shortfall	211	Length
2029	(324)	Shortfall	126	Length
2030	(693)	Shortfall	134	Length
2031	(767)	Shortfall	131	Length
2032	(796)	Shortfall	157	Length
2033	(869)	Shortfall	137	Length
2034	(891)	Shortfall	126	Length
2035	(913)	Shortfall	117	Length
2036	(938)	Shortfall	108	Length
2037	(1006)	Shortfall	111	Length
2038	(1317)	Shortfall	45	Length
2039	(1347)	Shortfall	54	Length
2040	(1377)	Shortfall	62	Length
2041	(1415)	Shortfall	56	Length
2042	(1456)	Shortfall	49	Length
2043	(1568)	Shortfall	57	Length

This table shows the capacity length generated through the preferred portfolio. Staff understands that this reflects actions taken by the company prior to the 2023 IRP, including:

- 100 MW of solar and 96 MW of four-hour storage added in 2024,
- 200 MW of solar added in 2025 for a clean energy customer, and
- 227 MW of four-hour storage added in 2025 from the 2024 RFP.

The Preferred Portfolio includes 261 MW of capacity from the Valmy conversions by 2026. By 2027, the Preferred Portfolio is capacity long by 284 MW, which appears to counter the argument for an urgent capacity need by 2028 and contributes to an uncertainty regarding the timing and volume of resource needs. That said, Staff is sensitive to the volatility of available capacity in the WECC and intends to work closely with the Company to understand how the 2028 RFP aligns with its current and near-term capacity needs.

In conclusion, Staff supports acknowledgement of Action Item 6, especially insofar as it is economic. However, the peak load the Company is addressing relies on large ESA customer load, for which there is little historical precedent. This makes it challenging to confirm the reasonableness of the volume and timing of the stated need. Staff appreciates the challenge the Company faces in procuring the resources needed to meet potentially large near-term changes in load. Staff looks forward to working with the Company to address RFP design and sensitivities to inform the selection and procurement of economic resources in the Company's 2028 RFP (Docket No. UM 2317).

Alignment of RFPs with IRPs

In Final Comments, Staff raised two issues with the current procurement process: 1) maintaining alignment with an acknowledged IRP, and 2) ensuring adequate time for Staff, stakeholders, and the Independent Evaluator to review RFPs. As the Company is on the path of rapidly procuring its energy and capacity needs to meet the robust load growth in the longer term, Staff sought a roadmap of procurement activities connected to future IRPs. Staff expects future IRPs to describe the Company's anticipated cadence of RFPs.

In its final comments, RNW agreed with Staff's draft recommendation of elaborating on its cadence of RFPs and identifying the future IRPs to which RFPs will be connected, "to avoid the complicated sequence of resource plans and procurements that have played out around Idaho Power's 2023 IRP."[52]

In response, the Company clarified that there may not be a direct connection between future IRPs and expected RFPs due to the evolving nature of the Company's capacity position.

Staff understands the challenges the Company faces and does not expect precision in the cadence of RFPs, but still expects future IRPs to include more detail about procurement strategies. Staff would like this to include a strategy for rapid, but well supported, procurement efforts; identification of the IRPs to which RFPs would be connected; and approaches to procuring competitively priced long lead time resources. Staff appreciates IPC's creativity, flexibility, and focus in its current 2028 AS RFP and looks forward to working with the Company and stakeholders to see lessons learned reflected in its future procurement strategies.

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[52] *See* Docket No. LC 84, RNW's Final Comments, May 23, 2024, p. 2.

Regulation Reserves and System Reliability

System Reliability

In Opening Comments, Staff noted that there had been no notable increase in the capacity of new fast-ramping dispatchable resources in the 2023 IRP to balance the variability of renewables. Staff also commented that it was unclear how much regulation reserves provided by flexible resources would be needed and whether it had been accounted for in the Aurora model.

In Reply Comments, Idaho Power argues that, unlike exits from coal units, the four additional coal-to-gas conversions for Valmy units 1 and 2 and Bridger units 3 and 4 result in a considerable increase in the amount of flexible dispatchable capacity to provide regulation reserves. The Company states that this flexible capacity has been accounted for in resource planning because the regulation reserves is modeled as a constraint that signals the addition of flexible dispatchable resources to balance increased variable energy resource penetration, as needed.

In response to Staff IR 135 requesting a comparison of the ramping constraints of the converted Valmy units to a SCCT at all modes of operation, the Company provided the information in Table 8.

Table 8: Valmy (260 MW) ramp rates – table reproduced from IPC's response to Staff IR 135

Characteristic	Valmy Gas	SCCT
Cold Start time	1 Day	1 hour
Minimum up time	5 days	2 hours
Minimum down time	1 Day	1 hour
Minimum generation	20%	50%
Ramp Rate % (Nameplate Capacity/Minute)	1.7%	8.4%

Staff concludes from Table 8 that for peaking and regulation reserve purposes there are significant differences between the characteristics of the Valmy and SCCT units. To get a better picture of the flexibility of the converted units, Staff expects that the Company provide in the next IRP the projected running hours of the converted gas units for regulation reserves and how they compare with SCCT or 4-hour batteries.

System Resilience

In Opening Comments, Staff raised the issue of how having high penetration of Variable Energy Resources (VERs), represented in the high volumes of wind and solar resources, may impact system resilience in the long term.[53] Staff was concerned about the means and costs of providing ancillary services needed to preserve system resilience in the face of high penetration of renewable resources towards the end of the planning period.

In Reply Comments, the Company explained that only regulation reserves are modeled as an ancillary service in the IRP, but not the other types of ancillary services to preserve system resilience.

Staff is concerned that, as the penetration of renewables increases towards the end years of the renewable dominated portfolios, it is unknown if the costs for ancillary services required for system resilience are significant enough to impact the overall portfolio cost. As such, Staff expects the Company to provide in the next IRP a description of how modeling co-optimized ancillary services in developing the preferred portfolio and to the extent it has any impact on portfolio costs.

Staff has three expectations for the Company to implement in the next IRP, or in future IRPs, related to:

a) Elaboration on the Company's anticipated cadence of RFPs and identification of future IRPs to which expected RFPs will be connected.
b) Information of the forecasted performance of the converted Valmy units to provide regulation reserve compared to other resources for balancing the intermittency of the renewable generation.
c) The inclusion of constraints related to system resilience in portfolio modeling if the costs of mitigation measures are significant to portfolio cost.

A discussion on these Staff expectations and the Company's responses to them is described in Attachment 2.

Recommendation 2: Acknowledge Action Item 6: If economic, acquire up to 1,425 MW of combined wind and solar in 2026-2028.

3. Transmission

Idaho Power's 2023 IRP includes acknowledgement requests related to three transmission projects: Phase 1 of Gateway West to facilitate access to renewable energy from east to west, bringing Boardman to Hemmingway online by June 2026, and continued exploration of SWIP-North for expanded market access. Staff is supportive of the action items of bringing the GWW Phase 1 online and the potential participation in

[53] See Docket No. LC 84, Idaho Power 2023 IRP, Staff's Opening Comments, February 7, 2024, pp. 16-17.

SWIP-North transmission line. Staff does not believe that there is a need for the re-acknowledgement of bringing B2H online because the procurement of the B2H project is already underway.

Gateway West Phase 1
Idaho Power seeks acknowledgement to bring Phase 1 of Gateway West (GWW) online by 2028, explaining that it enables the model to select the connection of 1,000 MW of low-cost renewable resources. Staff supports the acknowledgement of bringing the first phase of GWW online by 2028.

As part of the Gateway West Transmission System, Gateway West Phase I relieves Idaho Power's constrained transmission system between the Magic Valley and the Treasure Valley and the constraint between the Mountain Home area and the Treasure Valley (Boise East), in Idaho. As shown in Figure 7, Gateway West Phase I consists of two segments. The first segment (segment 8) is a new Midpoint–Hemingway #2 500kV line from the Midpoint substation near Shoshone, Idaho to Hemingway substation near Melba, Idaho (red line in Figure 7). This segment will require the construction of a new Mayfield substation southeast Boise, where the new 500 kV line and associated new resources into the Treasure Valley 230-kV system. The second segment (segment 10) is a new Midpoint–Cedar Hill 500-kV line from Midpoint substation to a future Cedar Hill substation (blue line in Figure 7). This segment will connect to the future PacifiCorp's Populus–Cedar Hill 500-kV segment to enable PacifiCorp to use its capacity gained via participation in the Midpoint–Hemingway #2 500-kV line.

Figure 7: Gateway West map–Magic Valley to Treasure Valley segments 8, 9, and 10

The 2023 IRP identified the need to include three GWW phases within the 20-year planning period in the Preferred Portfolio. In the near-term, IPC's modeling demonstrates that selection of the GWW Phase 1 addition enables the interconnection of an additional 1,000 MW of wind and solar resources. Leveraging the continuation of tax credits with wind and solar resources plus the significant increase in the Company's near-term load forecast triggered GWW Phase 1 to be selected as a least-cost solution.

Portfolio analysis shows that the alternative "Without [all] GWW Phases" will cost in excess of $500 million more than the preferred portfolio due to adding new gas facilities near load centers.[54] An added benefit of introducing GWW is the interconnection of new renewable generation, which supports the CO_2 emission reduction target of 100 percent clean energy by 2045 that the Company is pursuing.[55]

The second segment (segment 10) of GWW Phase 1 between Midpoint and a future Cedar Hill substation is part of an asset exchange between Idaho Power and PacifiCorp in the B2H Agreement. This segment will enable Idaho Power to acquire 200 MW of

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[54] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 136 for comparison of portfolio costs and Appendix C, p. 42 and p. 48 for details of resources in the "Preferred Portfolio–Valmy 1&2" and "Without GWW Segments" portfolios, respectively.

[55] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 34.

bidirectional transmission capacity between the Idaho Power system (Populus substation) and Four Corners, through Mona, Utah. At the same time of B2H coming online, the Company explains the connection to the Four Corners hub, with a presence of eight market entities,[56] would enable connectivity to regions rich in solar and wind potential.

RNW and IPC support Staff's recommendation to acknowledge Action Item 8.

Recommendation 3: Acknowledge Action Item 8: Bring the first phase of Gateway West (GWW) online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation) by end-of-year 2028.

B2H

The Company is seeking acknowledgement of Action Item 4 to bring B2H online by summer 2026. Consistent with the Commission's acknowledgement decisions in the past on action items that request acknowledgement for fully committed projects, Staff does not recommend acknowledgement of this action item.[57,58]

In Final Comments, Staff recommended non-acknowledgement of Action Item 4 because the procurement of the B2H project was already underway.[59] Idaho Power responded that the B2H-related Action Item from the 2021 IRP and the 2023 IRP were not the same and that Staff misunderstood the current B2H action item. The Company understood Staff's recommendation against acknowledgement as being related to the B2H delays from July 2026 to November 2026.[60,61] The Company suggested acknowledgement with the condition of a timing update in the 2025 IRP, rather than not acknowledging this critical resource.

Staff agrees that the action items regarding B2H between LC 78 and LC 84 are different, but they are directly related. Staff did not base its recommendation for non-acknowledgement on the literal reading of the action item with regards to project delays.

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[56] The eight entities having transmission connectivity include Arizona Public Service; Salt River Project; Tri State G&T; Western Area Power Administration; Xcel Energy; Public Service New Mexico; Tucson Electric Power Company; and PacifiCorp (see Table 7.6 in Idaho Power, 2023 IRP, September 29, 2023, p. 86).

[57] An example of the Commission not acknowledging RNG project that is substantially completed can be found in in Docket No. LC 83, Cascade Natural Gas 2023 IRP, Order 24-158, p. 10.

[58] Another example of the Commission supporting Staff's recommendation to not acknowledging Jackpot Solar can be found in Docket No. LC 78, IPC 2021 IRP, Order 23-004, Appendix A, p. 26.

[59] *See* Docket No. LC 84, Staff's Final Comments, April 25, 2024, p. 4.

[60] *See* Docket No. LC 84, Idaho Power Company's Final Reply Comments, May 23, 2024, p. 4.

[61] *See* Docket No. LC 84, Idaho Power, Idaho Power's 2023 Integrated Resource Plan: Update on Boardman to Hemingway Timing, April 19, 2024.

Staff considers that project delays are not uncommon, and that B2H is most likely to be delivered within the near-term action plan of the 2023 IRP, given the current delays. In the past, the Commission has not acknowledged items that have already been executed or substantially completed including in Idaho Power's most recently acknowledged IRP and other IRPs.[62] Staff wants to make it clear that its recommendation for non-acknowledgement of Action Item 4 does not mean Staff found evidence that the investment in this resource is unreasonable.

Staff's opinion is that an acknowledged action item that spans more than one IRP generally should not need re-acknowledgement unless something about the action item has deviated significantly from how it was presented for acknowledgement, e.g. a change requiring a decision whether to greatly change or abort the project. Staff sees this akin to direction in IRP Guideline 3(f) regarding the requirement to file an IRP "Once a utility anticipates a significant deviation from its acknowledged IRP…."[63] There are three reasons for this approach: 1) so there is no confusion on when the action item was acknowledged, 2) to save time and effort by eliminating a need to request and subsequently consider acknowledgement on an action during its implementation, and 3) any new request for acknowledgement becomes more significant as it signals a deviation from a previously acknowledged action item.

Had there been a new major factor that put the economics of continuing with the project into question, Staff would have recommended the Commission to acknowledge or not acknowledge the continuation of the project contingent on Staff's assessment of the viability of the business case given the new factor. Absent any major factors impacting the practicability of B2H, Staff continues to recommend non-acknowledgement of Action Item 8.

No stakeholders provided comment on the B2H Action Item 4.

Recommendation 4: Not acknowledge Action Item 4: Bring B2H online by summer 2026.

SWIP-North

Idaho Power seeks acknowledgement to continue exploring the Company's potential participation in the SWIP-North project in 2024, which could enable access to up to 500 MW of renewable resources from the Desert Southwest market during peak winter

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[62] *See* Order No. 23-004 (Docket No. LC 78), p. 1, where the Commission adopted Staff's recommendation to not acknowledge the Jackpot Solar action item due to substantial completion, *and* Order No. 24-158 (Docket No. LC 83), p. 10, where the Commission agreed with "Staff's recommendation that CNG's renewable natural gas action items not be acknowledged because that resource procurement is substantially completed."

[63] See Docket No. UM 1056, Order No. 07-002, January 8, 2007, p.9..

demand and other benefits. Staff supports Idaho Power's efforts to diversify its access to wholesale electricity markets through this action item.

The 2023 IRP anticipates the reduction in winter resources from the Pacific Northwest region during the peak winter season in the late-2020s.[64] As discussed in Staff's Final Comments, the Peak Hour Mid-C Average Daily Trading Volume is showing a declining trend since 2014, where in the early years 2014-2016 there were more than 50,000 MWhs traded. By 2023, the trading volume reduced to around 30,000 MWhs.[65] The Company proposes addressing this by diversifying its access to the Desert Southwest market in two ways. First, it explains that B2H unlocks 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus substation) and Four Corners, through Mona, Utah. Second, participation in the SWIP-North transmission project would provide access to the Desert Southwest market starting in 2027 by creating a south-to-north capacity of more than 1,000 MW.

Based on historical information regarding the Desert Southwest summer and winter peaks, Idaho Power claims that the forward-looking forecast shows a consistent yearly differential of 13,000 MW between summer peaks and winter peaks. The excess capacity in the winter season could serve Idaho Power's needs, while being complementary with the relatively lower winter demand of other utilities in the southwest.[66]

According to the analysis performed by the Company in the 2023 IRP, building on a sensitivity analysis in the 2021 IRP, the SWIP-N shows potential cost savings providing a 500 MW resource equivalent capacity from the Desert Southwest in the winter months beginning in 2027.[67] Staff generally agrees. While there are many cost details not yet known for the SWIP-North project, Staff sees the of surplus solar energy in winter should translate to competitively priced renewable resources from the Desert Southwest. However, Staff is keen to know more about the cost effectiveness of the project once commitments from partners have been finalized.

In Final Comments, Staff recommended that the Company update the Commission with the latest developments with the SWIP-North project and how the outcomes of this project could alter the selection of the Preferred Portfolio. At the time of finalizing this report, the Company informed Staff that there were no outcomes yet from the negotiations with other parties. As such, Staff withdraws its draft recommendation in Final Comments of briefing the Commission with project outcomes, maintains its

[64] See Docket No. LC 84, Idaho Power 2023 IRP, September 29, 2023, pp. 81-82.
[65] See Docket No. LC 84, Idaho Power 2023 IRP, Staff's Final Comments, p. 33,
[66] See Docket No. LC 84, Idaho Power 2023 IRP, September 29, 2023, p. 96.
[67] See Docket No. LC 84, Idaho Power Company 2023 IRP, pp. 94-95.

support for acknowledgement of Action item 1, and looks forward to the results of the SWIP-North participation initiative in the 2025 IRP.

Recommendation 5: Acknowledge Action Item 1: Continue exploring potential participation in the Southwest Intertie Project (SWIP)-North project in 2023-2024.

4. Distribution-Connected Storage

Following the Company's first installation of 11 MW of distribution-connected storage at four substations, and a preferred portfolio that adds a maximum of 5 MW of 4-Hour storage every year from 2027 to 2042, Idaho Power seeks acknowledgement to install 10 MW of cost-effective distribution-connected storage in 2025-2028.[68] *Staff supports this action item and seeks additional details in future IRPs.*

IPC explains that, starting in 2027, it would pursue 5 MW of distribution-connected storage projects every year until 2043. The cost-effectiveness of these projects would be determined by the Oregon Distribution System Planning process, which also informs the locational value of distribution-connected resources.[69,70] These are then reviewed by Idaho Public Utilities Commission (IPUC) and the prudency of the investments would be determined in separate filing such as a general rate case.[71]

Staff supports distribution-connected storage as a new resource to meet system needs, where cost-effective. However, Staff notes that all four of the Company's first projects experienced in-service delays due to damage to equipment during testing and a fire event in one substation. Considering batteries play a crucial role in the energy transition, the Company should share information regarding the incorporation of best-practices in battery project construction, commissioning, and operations. Staff expects that lessons learned from Idaho Power's first installation of distribution-connected storage will inform how these types of projects are modeled and considered in future planning. See Attachment 2 for additional details about Staff's expectations on this topic.

Recommendation 6: Acknowledge Action Item 3: Install cost effective distribution-connected storage from 2025 through 2028.

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[68] See Docket No. LC 84, IPC's Response to Staff's IR 76, where the company said that the LTCE model selected 5 MW of 4-hr distribution-connected storage every year between 2027 and 2042.

[69] For an example of the explanation of the grid needs assessment to determine cost-effective projects for Idaho Power's Oregon service area, see Docket No. UM 2196, 2022 Oregon Distribution System Planning Report: Part II, August 15, 2022, Table 4.2, pp. 44-49.

[70] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 73.

[71] See Idaho Public Utilities Commission, Case Number IPC-E-23-23, Comments of the Commission Staff, February 15, 2024, p. 17, for the process on how distribution-connected storage projects are assessed by IPUC.

5. Long Duration Storage

Idaho Power is seeking acknowledgement to explore the creation of a long duration storage pilot in 2024-2028 that could enhance the Company's understanding of long duration storage operational characteristics.[72] Staff is generally supportive of Idaho Power's plan to evaluate whether such a pilot program is feasible and of value.

In the 2023 IRP, Idaho Power describes long duration storage as resource for providing a grid service in the form of shifting energy between seasons.[73] Based on the Company's knowledge of the cost and operational characteristics of this new type of storage technology, the Company introduced long duration storage in the resource mix of the 2023 IRP.[74] Long duration storage was selected by the LTCE model for every portfolio presented by the Company in the 2023 IRP.[75]

Action Item 3, however, is about Idaho Power staff gaining practical operational experience with long-term storage and "to better understand how to optimize long-duration storage dispatch on a small scale, before potentially adding large amounts onto the system in the future".[76] This would include developing a practical understanding of such things as round-trip efficiency, charge and discharge rates, and degradation.

In its response to Staff's IR 140, the Company confirmed that the action item for which it is seeking acknowledgement is not a long duration storage pilot project, but rather investigating the feasibility of a long duration storage pilot project.[77] Idaho Power further explained that if the pilot project appears valuable, then details of the findings and reasons for pursuing the pilot project will be provided to the Commission in a separate regulatory filing.

While Staff welcomes the idea of introducing new technology such as long duration storage that can help the transition to clean energy, it offers that a pilot project needs to have clear purpose and outcomes. The Company should be able to explain what practical experience would be achieved from a pilot that would not be achieved by alternative means, such as practical training of operational staff at an established long duration storage site. Apart from evaluating the cost and risk of the pilot project, which the Company cites as the primary factors considered,[78] Staff reminds the Company that

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[72] See Docket No. LC 84, IPC Response to Staff IR No. 139.
[73] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 64.
[74] *Ibid*, p. 65.
[75] For example, see Figure 3 for the Nov2026 B2H Valmy 1 & 2 portfolio, where 200 MW of 100-Hr storage is introduced in 2038.
[76] See Docket No. LC 84, IPC Response to Staff IR No. 139.
[77] See Docket No. LC 84, IPC Response to Staff IR No. 140.
[78] See Docket No. LC 84, IPC Response to Staff IR No. 140.

the Commission has guidelines for the assessment and approval of pilot projects if the cost of the pilot project will be later presented in a rate case. Staff suggests that Idaho Power consider past Commission investigations and orders pertaining to pilots as it develops its approach (specifically Docket No. UM 2141, Order No. 22-115).

Recommendation 7: Acknowledge Action Item 2: Explore a 5 MW long-duration storage pilot project between 2024 and 2028.

6. WRAP Benefits Modeling

Idaho Power seeks acknowledgement to include 14 MW of capacity benefits associated with its participation in the Western Resource Adequacy Program (WRAP) beginning in 2027. The Company is leveraging the WRAP's operational program offering of 14 MW from other WRAP participants once a year during the time of greatest need for Idaho Power. Staff supports this action and looks forward to the Company's initiative to continue refining future WRAP modeling methods in future IRPs.

The goal of the WRAP, of which Idaho Power is a participant, is for participants to share capacity among themselves during short-time periods of resource deficiency due to peak load conditions or extreme weather events.[79] The Company added the leveraging of 100 MW of capacity provided by other WRAP participants and made this capacity available to its Reliability and Capacity Assessment Tool (RCAT) model once per year starting in 2027.[80] RCAT analysis shows that such capacity will result in Idaho Power reducing its resource need by 14 MW of perfect capacity to lower the risk of the highest-risk day each year to meet the industry standard of 0.1 event-days per year LOLE. The Company stated that it would develop a more refined understanding of how often it relies on the WRAP as it gains more operational experience with WRAP operations program.[81]
Staff agrees with the Company's first attempt regarding modeling WRAP once a year, as it matches the intent of the program. Staff also agrees with the Company that refinements will naturally follow by all participants as they become more familiar with the program. As such, Staff supports the action item to include WRAP as a resource at times of highest need.

On April 22, 2024, the Western Power Pool (WPP) announced that WRAP has delayed its first binding season until summer 2027. In the meantime, WRAP members intend to work on a transition plan to make a summer 2027 binding season feasible.[82] Staff

[79] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, pp. 30-31.
[80] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix C, p. 91.
[81] *Ibid*.
[82] WPP (westernpowerpool.org), "Western Power Pool Statement in Response to WRAP Participant Letter to Stakeholders", April 22, 2024, available at https://www.westernpowerpool.org/news/western-power-pool-statement-in-response-to-wrap-p, accessed on July 2, 2024.

notes that a 2027 binding season still aligns with the Company's choice to model WRAP benefits beginning in 2027. While the transition plan creates some uncertainty about whether the structure of the WRAP will remain the same as it currently is, Staff still believes that the choice to model some level of benefits beginning in 2027 remains reasonable given the information currently available.

Recommendation 8: Acknowledge Action Item 7: Include 14 MW of capacity associated with Western Resource Adequacy Program (WRAP) in 2027.

Issues Outside of the Action Plan

7. Wind Qualifying Facilities (QFs)

In the 2023 IRP, the Company assumed a zero wind QF renewal rate in base planning. Assuming that no wind QFs will renew will result in the utility likely overestimating its resource needs and over procuring resources. Both Staff and Stakeholders recommend that Idaho Power develop a reasonable non-zero estimate of a wind QF renewal rate in the next IRP, and until such rate is established, it should adopt a wind QF renewal rate of 75 percent.

Consistent with the assumptions in the 2021 IRP, the Company assumed in the 2023 IRP base planning that none of the wind QFs will renew their energy sales agreement with Idaho Power when their existing contracts expire.[83] Staff and stakeholders both found this approach unreasonable and offered direction as to what renewal rates should be. Staff first addresses why a non-zero rate is unreasonable and then addresses considerations for what the renewal rate should be.

Non-Zero Wind QF Renewal Rate in Base Case

The Company's assumption of a zero wind QF renewal rate is not in line with the direction of Order No. 21-184, which said modeling of renewals should include some percentage, rather than taking an unrealistic "all or nothing" approach.[84]

Idaho Power rejected the notion that a non-zero wind QF renewal was unreasonable. It noted 1) that informal conversations with several QFs indicated lack of intention to renew;[85] 2) that renewal assumptions were based on the best information available at

[83] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 128.
[84] *See* Order No. 21-184 in Docket No. LC 74, Idaho Power 2019 IRP, June 4, 2021, p. 19.
[85] *See* Docket No. LC 84, Idaho Power's Reply Comments, March 7, 2024, pp. 51-52.

the time; [86] and 3) its non-zero assumption is conservative and aligns with IPUC direction in IPUC Order No. 34959.[87,88]

In supplemental comments, REC disputes the Company's interpretation of the IPUC Order No. 34959 saying it fails to explain the different regulatory paradigms in Idaho and Oregon.[89] To illustrate that concept, REC elaborates that unlike the Oregon PUC, the IPUC "does not opine or endorse any specific planning assumption in the IRP or direct a utility to assume something specific," but rather makes sure the utility follows the Idaho IRP rules.

Staff Analysis
Staff contacted IPUC Staff to understand their view on the issue.[90] IPUC Staff did not object to Idaho Power's assumption of a zero percent wind QF renewal because of two reasons: 1) Idaho Power's assertion that they spoke with the wind QFs, and the QFs indicated they would NOT renew, and 2) Since the State of Idaho changed the QF contract duration policy for new large QFs, IPUC Staff assumes that *existing* large QFs will not choose to renew in recognition that new large QFs have stopped in Idaho under that revised contract duration policy, but also due to aging equipment or due to more lucrative alternatives.[91] In summary, IPUC Staff concluded that the evidence they have seen suggests that Idaho Power's assumption is reasonable and more conservative for reliability. However, they are open to contrary evidence.

The Company communicated in final comments that at the time of IRP modeling, conversations with QF projects indicated an intention to not renew. However, it did not provide supporting evidence in support of this finding. Conceptually, lack of renewal data does not justify an assumption of zero value or any value, unless there are factors to suggest otherwise, such as prohibitive changes in the rules, compelling market changes, or other reasons. As in Staff's Comments in the PGE 2023 IRP, it would be best to see the Company develop some percentage estimate with an equal likelihood of under- and over-estimating the actual renewal rate.[92] A zero renewal rate does not provide this balance.

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[86] *See* Docket No. LC 84, Idaho Power's Final Reply Comments, May 23, 2024, p. 16.
[87] Idaho Public Utilities Commission, Idaho Power – Application for Acceptance of 2019 Integrated Resource Plan, Case No. IPC-E-19-19, Order No. 34959 at 26 (Mar. 16, 2021), available at: https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1919/OrdNotc/20210316Final_Order_No_34959.pdf.
[88] *See* Docket No. LC 84, Idaho Power's Final Reply Comments, May 23, 2024, p. 17.
[89] See Docket No. LC 84, REC's Supplemental Comments, June 10, 2024, pp. 2-3.
[90] Email to IPUC, June 11, 2024, 4:20 pm.
[91] Email from IPUC, June 12, 7:53 am.
[92] *See* Docket No. LC 80, Order No. 24-096, p. 24.

Despite arguments that wind QFs would not renew due to Idaho's new QF contract duration policy changes for new QFs or other factors, Idaho Power, in its response to IR 19 by REC, mentioned an application made on April 2, 2024 by a wind QF.[93] In the same response, the Company stated that it received emails from some wind QFs stating that they intend to enter into replacement contracts when their current contracts expire. Both of these pieces of information go against the notion of the assumption of no renewals for wind QFs.

Renewal Rate Calculation
Staff and stakeholders suggested various options for a non-zero wind QF renewal rates that Idaho Power should use and the timing of the application of those rates.

Based on its discussions with current wind QF operators, REC recommended that the Commission direct Idaho Power to update the 2023 IRP planning assumptions of wind QF renewal percentage to 85 percent.

In Final Comments, Staff recommended Idaho Power work with Staff and Stakeholders on a non-zero wind QF renewal rate in the lead up to the 2025 IRP and verify its assumptions against the outcome of actual renewal decisions at the same time. In the interim, Staff recommends that Idaho Power follow a similar Commission directive to PGE in Docket No. LC 80 and utilize an assumption of 75 percent for wind QF renewal rate until a non-zero renewal rate is derived by a methodology accepted by the Commission.[94] This recommendation follows an approach similar to PacifiCorp's vetted and approved approach.[95] And as an interim solution for IPC, a 75 percent renewal rate provides a reasonable approach based on empirical evidence with an equal likelihood of under and overestimating the actual renewal rate.

In its final reply comments, the Company objected to "prescriptive approaches to modeling that do not consider the nuances of a given utility's customers or service area."[96] Similarly, with regards to Staff's draft recommendation for the Company to adopt a 75 percent wind QF renewal rate in the interim, the Company requested the Commission not adopt highly prescriptive language because it leaves no room for discussion and feedback from the IRPAC.[97]

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[93] *See* Docket No. LC 84, IPC's Response to REC IR No. 19.
[94] *See* Docket No. LC 80, PDE 2023 IRP and CEP, Staff Report for the January 18, 2024 Special Public Meeting, December 14, 2024, pp. 24-25.
[95] *See* Docket No. LC 82, PacifiCorp 2023 IRP and Clean Energy Plan, PacifiCorp's Amended 2023 IRP, May 31, 2023, Appendix B, p.39.
[96] *See* Docket No. LC 84, Idaho Power's Final Reply Comments, May 23, 2024, p. 16.
[97] *Ibid*, p. 18.

In response to Staff's draft recommendation for the Company to work with Staff and Stakeholders on a methodology resulting in a non-zero wind QF renewal rate, the Company expressed concern with the notion that one methodology or approach should not apply to all three utilities, as PURPA did not uniformly impact the three utilities.[98] However, the Company indicated that it was open to considering a different approach, such as a new or different QF scenario, in consultation with IRPAC.[99]

Staff Analysis

Staff believes a zero-renewal rate is unreasonable. The Company's 2025 IRP is anticipated to be filed in June 2025 and the modelling work for the next IRP is just starting. Assuming Idaho Power follows its policy of reaching out to QFs 8-10 months prior to contract expiration, there are two wind QFs with expiring contracts for which renewal status will be known in time to inform the 2025 IRP wind QF renewal rate. Staff retains its recommendation, which provides an interim QF renewal rate until such time as the Company can work with the IRPAC to develop and present a non-zero wind QF renewal rate for Commission approval.

After research and discussions with various parties on the topic of wind QF renewal rates, Staff concludes that the two draft recommendations relating to wind QFs renewal rate remain unchanged in Staff's Final Recommendation.

Recommendation 9: Prior to portfolio optimization for the next IRP, the Company must work with Staff and Stakeholders to determine and employ a non-zero renewal rate for all QFs in line with PacifiCorp's estimation methodology, or other similar methodologies, to be adopted in the 2025 IRP.

Recommendation 10: Idaho Power should assume a 75 percent wind QF renewal rate pending a non-zero renewal rate determination via a methodology accepted by the Commission in the next IRP.

8. Load Forecast

IPC's forecasted load anticipates growth. The Company forecasts an average annual 2.1 percent growth rate of energy demand and an average 1.8 percent annual growth rate in peak hour demand, both during the 20-year planning period. Although Staff identified methodological concerns with the Company's load forecasting, it does not see a consistent bias in a single direction for overall system load. Continued discussions between Staff and the Company on following best practices may lead to increased accuracy of load forecasting in future IRPs.

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[98] *Ibid*, pp. 16-17.
[99] *Ibid*, p. 16.

In Final Comments, Staff had some expectations regarding load forecasts for the next IRP, which the Company responded to in its final comments. Attachment 2 includes a discussion on the following expectations:

a) Methodological improvements related to sharing of a priori reasons for selection of variables.
b) Using the 50th percentile for the expected case load as opposed to the 70th percentile.
c) Steps taken to provide oversight for ESA customers' forecasting of load growth.

9. Wholesale Electricity Prices

Idaho Power derives wholesale electricity prices endogenously from its Aurora model as the means for forecasting wholesale market prices. Staff's analysis of comparing forecasted market prices with historical market prices shows an improvement in the accuracy of wholesale forecasted market prices over the 2021 IRP in the planning case. In the 2023 IRP, the average planning-case Mid-C market prices are within a reasonable range from the historical average monthly Mid-C prices observed in early 2024.

In Final Comments, Staff had some expectations regarding wholesale electricity prices for the next IRP, which the Company responded to in its final comments. A discussion on Staff's expectations is included in Attachment 2 and relates to:

a) The Company sharing hourly wholesale market prices for the stochastic risk analysis.
b) Investigation of the possibility of the model overestimating the supply of resources in the Mid-C market.

It is envisaged that the ongoing exchange of data and ideas on validation of modeled prices between Staff and the Company will improve the accuracy of forecasted market prices in future IRPs.

10. Energy Efficiency (EE)

The 2023 IRP shows a decline of 80 MW of cumulative cost-effective energy efficiency measures decremented from the load forecast, as compared to the 2021 IRP. Additionally, no EE bundles were selected by the Aurora model in the Preferred Portfolio. Underestimated forecasted market prices from the 2021 IRP and other factors may have contributed to the fall in the avoided cost that resulted in lower EE measures in this IRP. The Company agreed to evaluate different EE bundle options after further discussions between members of Energy Efficiency Advisory Group and the IRPAC in preparation for the next IRP.

Idaho Power determined cost-effective EE quantities in the 2023 IRP using the avoided cost data from the Company's 2021 acknowledged IRP in LC 78.[100] According to the EE Potential Study performed for Idaho Power by AEG, the avoided cost calculation is based, amongst other factors, on forecasted wholesale market prices. As Staff included in this IRP, IPC's 2021 IRP had lower overall forecasted market prices compared to the more accurate prices in the 2023 IRP. A low forecasted market price estimate resulted in a low EE avoided cost in the 2023 IRP.

In Final Comments, Staff referred to the Company's response to IPUC Staff's request that it was adopting a new approach to mitigate the effect of a 'stale' avoided cost calculation on the determination of cost-effective EE measures.[101] In following this new approach, IPC will be changing the avoided cost calculation methodology from relying on the most recently "acknowledged" to the most recently "filed" IRP avoided costs in its energy efficiency program planning for 2024 and beyond. On the basis of the new methodology, Staff raised a draft recommendation to change the avoided cost methodology to rely on the most recently "filed" rather than the most recently "acknowledged" IRP in the 2025 IRP and future IRPs.

After a meeting with Staff for clarification, the Company explained that the response to IPUC was related to the energy efficiency program planning, as for 'implementation' of EE and not for the EE potential studies. In its reply comments to Staff's Final Comments, the Company confirmed that it already uses the most recently filed information for its EE potential studies. Due to the fact that the EE study is usually concluded before the new IRP is acknowledged, the avoided cost in any one IRP will be using the inputs from the previous IRP. For the 2025 IRP, the avoided cost calculation will be done in mid-2024 and will be using the filed 2023 IRP as input, which is anticipated to be acknowledged by July 30, 2024.

Based on the clarification provided by the Company, Staff retracts its draft recommendation. Although there will always be a lag in the input to the EE avoided cost calculation, Staff expects that the 2025 IRP will have a more accurate EE avoided cost because the cost will be based on more realistic wholesale market prices.

Apart from the marginal cost of energy, which matches Idaho Power's zonal price in the 2023 IRP Preferred Portfolio, EE measures also receive a benefit associated with avoided or deferred capacity valued at the levelized cost of a Simple Cycle Combustion Turbine (SCCT). There are also benefits associated with avoided or deferred capacity from transmission and distribution investment, as well as a benefit associated with

[100] *See* Docket No. LC 84, IPC Response to Staff IR 130.
[101] See Idaho Public Utilities Commission, Case Number IPC-E-23-23, Company Reply Comments, February 29, 2024.

avoided line losses. Staff agrees that the avoided cost calculation can produce different results from one potential study to the next due to the change in the afore-mentioned input costs at the time the potential study is conducted.

In Final Comments, Staff had one expectation regarding EE for the next IRP, which the Company responded to in its final comments. Staff's expectation is related to the costs and benefits of portfolio runs with more 'low-cost' bundles. A brief discussion on this expectation is included in Attachment 2.

11. Demand Response (DR)

In the 2023 IRP, the Company used an Idaho Power-specific potential study to inform the modeling of additional DR, and this approach addressed many of Staff's concerns from the 2021 IRP. Staff would like to explore the benefits, if any, of using a smaller DR block size in the model during discussions with the IRPAC for the development of the 2025 IRP. The current block size is 20 MW. Staff believes the Company should investigate smaller 10 MW blocks to align with the anticipated growth of the resource of 5 MW to 13 MW in reality.[102]

In Final Comments, Staff had one expectation regarding DR for the next IRP, which the Company responded to in its final comments. Staff's expectation is related to exploring the benefits or drawbacks of using smaller DR block size for selection by the model. A brief discussion on this expectation is included in Attachment 2.

Waiver Request

In the Company's final reply comments on the 2023 IRP, Idaho Power requested a waiver of OAR 860-027-0400(11), which places an obligation on the utility to file an IRP Update of its most recently acknowledged IRP on or before the one-year anniversary of the acknowledgement date. The Company explains that its work on its 2025 IRP is underway, and it plans to file that IRP before July 30, 2025, which is the anniversary of the acknowledgement date of the 2023 IRP. As such, the filing of the 2025 IRP would essentially moot the need to file an IRP Update to the 2023 IRP.

Staff agrees with the Company's reasoning and recommends that the Commission waive the IRP Update requirement with respect to the Company's 2023 IRP. However, if the Company anticipates a significant deviation from this IRP within the first six months of the acknowledgement date of this IRP, this waiver does not exempt the Company from the requirement of filing an IRP Update, as per IRP Guideline 3(f).[103]

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[102] See Docket No. LC 84, Idaho Power 2023 IRP, Staff's Opening Comments, February 7, 2024, p. 37.
[103] *See* Docket No. UM 1056, Order No. 07-002, January 8, 2007, p.9.

Recommendation 11: Grant the Company a waiver of the Company's obligation to file an update to the 2023 IRP.

Conclusion

Staff appreciates the hard work of Idaho Power and each of the stakeholders participating in this proceeding. Staff has presented a series of recommendations throughout this report. All recommendations are summarized in Attachment 1 and expectations are summarized in Attachment 2.

PROPOSED COMMISSION MOTION:

Acknowledge Idaho Power Company's 2023 Integrated Resource Plan, except for one Action Plan Item that has already been substantially completed; approve Staff's recommendations for the 2025 IRP; and approve Staff's recommendation for granting the Company a waiver of the Company's obligation to file an update to the 2023 IRP.

<u>Attachment 1. Summary of Staff's Recommendations</u>

In acknowledgement of the IRP and the Company's request for a waiver regarding the IRP Update, Staff identified 11 recommendations:

IRP Acknowledgement

Recommendation 1: Acknowledge Action Item 5: Convert Valmy units 1 and 2 from coal to natural gas by summer 2026.

Recommendation 2: Acknowledge Action Item 6: If economic, acquire up to 1,425 MW of combined wind and solar in 2026-2028.

Recommendation 3: Acknowledge Action Item 8: Bring the first phase of Gateway West (GWW) online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation) by end-of-year 2028.

Recommendation 4: Not acknowledge Action Item 4: Bring B2H online by summer 2026.

Recommendation 5: Acknowledge Action Item 1: Continue exploring potential participation in the Southwest Intertie Project (SWIP)-North project in 2023-2024.

Recommendation 6: Acknowledge Action Item 3: Install cost effective distribution-connected storage from 2025 through 2028.

Recommendation 7: Acknowledge Action Item 2: Explore a 5 MW long-duration storage pilot project between 2024 and 2028.

Recommendation 8: Acknowledge Action Item 7: Include 14 MW of capacity associated with Western Resource Adequacy Program (WRAP) in 2027.

Recommendation 9: Prior to portfolio optimization for the next IRP, the Company must work with Staff and Stakeholders to determine and employ a non-zero renewal rate for all QFs in line with PacifiCorp's estimation methodology, or other similar methodologies, to be adopted in the 2025 IRP.

Recommendation 10: Idaho Power should assume a 75 percent wind QF renewal rate pending a non-zero renewal rate determination via a methodology accepted by the Commission in the next IRP.

Waiver Request

Recommendation 11: Grant the Company a waiver of the Company's obligation to file an update to the 2023 IRP.

Attachment 2. Staff Expectations for Future IRP

Staff's Final Comments highlighted a range of opportunities to improve the next IRP that Idaho Power may be prepared to address in its plan development process and the investigation into the Commission's planning and procurement policies expected in 2024. This is a list of expectations that Staff gained through its experience with the IRP review.

Staff believes its expectations are worth documenting at the end of this process for several reasons. First, to recognize the amount of effort that went into running concerns to ground and determining that it is acceptable to address the concerns through improvements in the next IRP. In addition, Staff seeks to promote continuity going into development of the next IRP and planning and procurement investigation. Staff also believes that this documentation will help Idaho Power understand and consider Staff's ideas as early in the next planning process as possible. Most importantly though, Staff presents its expectations in this manner to avoid the impression that they are comprehensive or rigid requirements for future planning. These are a starting point for future discussions amid rapidly changing conditions. Staff has seen Commission direction for future IRPs go stale but consume significant utility and stakeholder time on implementation. Staff seeks to avoid that here, as well.

If Idaho Power determines that there are negative impacts or insurmountable challenges to moving forward with one of these concepts, Staff looks forward to engaging in further discussions during the next IRP development process or planning/procurement investigation. That said, Staff appreciates the extensive feedback and provides updates and other responses below.

Coal to Gas Conversion:

1. Evaluate two alternative portfolios to address risks associated with coal to gas conversions:
    - Exit all coal plants by 2030 without Valmy and Bridger 3 and 4 conversions.
    - Delay Valmy conversion with a November 2026 online date for B2H.

IPC does not see value in the additional modeling in this expectation, as by 2025 the conversion of Valmy 1 & 2 will be underway and the Bridger unit conversions may not materialize. Instead, the Company suggests an alternative of scenarios in which the Valmy conversion timeline matches the construction timeline as knowable at the time of 2025 IRP analysis and that the most up-to-date info on the possible outcomes of Bridger units will drive the modeling.
Staff agrees that the decision on the Bridger 3 and 4 units will inform future studies. However, Staff sees values in modeling a scenario with no conversions at least for

understanding the impact of emissions. In addition, a scenario for a delay in Valmy conversion is still worthwhile as a delay in any project is a possibility.

2. The company should provide workpapers for the projected number of hours for both baseload and peaking operation of the Valmy coal-to-gas converted units, and the corresponding hours for CCCT, SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

IPC questions the benefit the large amount of data requested in the expectation, given the impact on model run-time. It also adds that the distinction between baseload and peaking is likely to be arbitrary at best and misleading at worst. It suggests that Staff strike "both baseload and peaking" from this expectation.

For understanding forecasted plant deployment and usage, Staff expects IPC to demonstrate in the next IRP the total hourly contribution of Valmy units in the Preferred Portfolio compared to the contribution of one resource from each other type mentioned, during peak and off-peak hours (or hours of highest risk) for at least a typical year in the planning period.

3. As suggested by RNW, IPC should evaluate an alternative portfolio with a "by" 2030 exit date from all coal operations and without the gas conversion of Valmy and Bridger 3 and 4 units for a better understanding of emissions implications of continued use of fossil fuel generation.

IPC suggests that it provide updates to the IRP Advisory Council (IRPAC) on developments at Bridger Units 3 and 4 and evaluate portfolios in the next IRP based on those developments. Staff stresses the need for scenario analysis in the next IRP for Bridger units 3 and 4 not being converted, as supported by RNW's concerns about the fate of these units after the developments stated in PacifiCorp's 2023 IRP Update.

4. In the lead up to the 2025 IRP, Idaho Power should provide cost estimates of SO_2 and NO_X emissions related to the converted plant, in its advisory IRPAC meetings and incorporate those costs in the Aurora model.

IPC clarifies that it models resources with a constraint that the emissions from those resources cannot exceed allowed emissions levels but has no data of costs. For transparency, IPC will discuss the modeling of emissions with IRPAC for future IRPs.

According to Subpart KKKK of the Code of Federal Regulations, standards of performance regulate the nitrogen oxide (NO_X) and sulfur dioxide (SO_2) pollutants from stationery combustion engines.[104] As in its expectation in Final Comments, Staff reiterates the need to include cost estimates for the SO_2 and NO_X emissions from the converted Valmy units in the next IRP, if such costs are significant enough to impact portfolio cost.

5. The Company should reflect recently introduced EPA rules for GHG emissions' Standards and Guidelines for Fossil Fuel-fired power plants in its 2025 IRP.

In its final comments, RNW noted that cost-effectiveness and timing of the coal to gas conversions could be impacted by the new Environment Protection Agency (EPA) standards for Greenhouse Gas Emissions recently released and effective on July 8, 2024.[105,106] Although Staff agrees with RNW's point that there is a possibility that the new EPA rule could impact the Preferred Portfolio, the new rule did not exist when Idaho Power developed the IRP. As such, Staff refers to IRP Guideline 3, where acknowledgement of the action item by the Commission is "based on information available at the time".[107] In this case, Staff is not inclined to modify its recommendation based on this new information. However, the Company has a regulatory obligation to provide the Commission with information about significant deviation from its 2023 IRP or its action plan if the change by the new EPA rule causes this significant deviation. Additionally, Staff expects Idaho Power to reflect the new EPA rules in its 2025 IRP.[108]

Wind and Solar Resources:

6. The Company should elaborate on its anticipated cadence of RFPs and identify the future IRPs to which expected RFPs will be connected.

A discussion on this expectation is included in the body of the Staff Report.

7. IPC should provide workpapers for the projected number of hours for regulation reserves operation of the Valmy coal-to-gas converted units, and the corresponding hours for SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

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[104] Code of Federal Regulations: Subpart KKKK—Standards of Performance for Stationary Combustion Turbines, accessed on June 28, 2024, available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-KKKK.

[105] *See* Docket No. LC 84, RNW's Final Comments, May 23, 2024, p. 4.

[106] Rule 89 FR 39798 - New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, May 9, 2024, available at https://www.govinfo.gov/app/details/FR-2024-05-09/2024-09233/summary.

[107] *See* UM 1056, Order 07-002, January 8, 2007, p. 10.

[108] Ibid, p. 11.

IPC is concerned by the impact on the model run time if it has to satisfy Staff's request of comparing regulation reserve hours of converted Valmy units with fast-acting resources. However, IPC will work with Staff to provide the most useful and necessary information. Staff elaborates on the expectation to provide the data is to increase its understanding of different types of dispatchable resources to balance renewable resources. For comparison purposes, the amount of data does not need to be large, as Staff is seeking the total hourly contribution of each type of resource providing regulation reserves service for at least a typical year in the planning period.

8. IPC should include the constraints related to system resilience in portfolio modeling if the estimated cost of ancillary services to preserve system resilience will be significant enough to warrant such inclusion.

IPC communicated that it can support Staff's expectation to continue including all constraints related to system resilience in its portfolio modeling. Staff agrees with the resolution.

Distribution-Connected Storage:

9. IPC must share information with Staff about lessons learned regarding the incorporation of best-practices in battery project construction, commissioning, and operations to mitigate operational risks.

IPC supports Staff's expectation to share information regarding batteries but argues that the IRP focuses on long-term planning and the characteristics of resources related to how they are modeled, selected, and priced—not the specific operational management of each resource. However, IPC will seek to incorporate lessons learned in the supply-side resource section of future IRPs, as information becomes available. Staff agrees with the resolution, but clarifies that lessons learned from the installation of distribution-connected storage resources have a direct impact on the safety, cost, and implementation time of this new technology for both near-term and long-term planning.

Load Forecast:

10. Idaho Power should document and share the a priori reasons for all econometric model specification.

IPC can furnish pertinent details for econometric modeling, such as out-of-sample performance, variable selection, correlation matrices, model statistics, and error metrics within Appendix A of forthcoming IRPs. Following the objective of selecting models with minimum errors, the Company confirms that it employs standard assumptions of econometric modeling and will provide in future IRP the outputs of: conditional distribution of errors given independent variables, the independence and identical distribution of data points, consideration of large outliers, and the absence of perfect multicollinearity. Staff agrees with the resolution.

11. Idaho Power should use the 50th percentile for the expected case load forecast in future IRPs.

In defense for using the 70th instead of the 50th load percentile, IPC argues that fixing both load forecast percentile and the LOLE threshold would leave it with few to no tools available for reliability planning. However, it stated that such technical decision should be discussed with Staff and Stakeholders in future IRPs.

Staff sees this issue as identifying a least cost portfolio given a constraint, which is the LOLE of 0.1. P70 is a conservative estimate of the load. IPC is basically rejecting the risk standard set in UM 2011. Staff is not opposed to using P70 as a scenario (high end of the load), but not for a planning base case. IPC explained that it was a valid way to account for extreme weather events and other reliability risks. With regards to the response to IPUC regarding the P70 choice, IPC calculated the LOLE over a range of peak load forecast percentiles (10th, 30th, 50th, 70th, 95th) utilizing the capacity positions to meet a 0.1 event-days per year LOLE threshold using both the P50 and P70 (as the two base cases) for all six test years used in the 2023 IRP analysis. By fixing the resources for each base case (P50 and P70), results show that using the P70 produces an average LOLE of 0.0965 across all the percentiles over the 6 test years, while using P50 produces an average LOLE of 0.1650. IPC claims that the former LOLE is closer to the LOLE target of 0.1. Based on the above justification, the questions here are:

- Why shouldn't it be P60 or P55?
- Why are the stochastic runs not sufficient to capture the extreme load events?

The conclusion for the 2023 IRP is that the principle seems unacceptable, but the outcome of its application is immaterial to resource need in this case. Staff welcomes further discussions on this technical issue with IPC and Stakeholders in future IRPAC meetings.

12. IPC should consider and demonstrate the steps taken to provide oversight for ESA customers’ forecasting of load growth.

IPC elaborated on the Company's interactions with ESA customers from construction to operation to ensure best practices on load projections and energy efficiency. The Company will endeavor to work with Staff to review ESA load forecasts in future IRPs. Staff agrees with the resolution.

Wholesale Electricity Prices:

13. IPC should preserve and be prepared to provide hourly wholesale electricity price data from the stochastic risk analysis.

After discussions with Staff, IPC agreed to provide hourly price data from the stochastic modeling from the major trading hubs that the Company purchases from. The data will consist of hourly zonal marginal electricity price data and not wholesale electricity price data at the nodal level. Staff agrees with the resolution.

14. IPC should investigate the possibility that migration of power sellers to balancing markets may cause Aurora to overestimate resources available for purchase by Idaho Power and report its findings in the next IRP.

IPC clarifies that the Western Energy Imbalance Market (WEIM) is an intra-hour imbalance market that seeks to optimize resource dispatch through regional arbitrage within the hour of a particular operating day and has no impact on day-ahead or longer-lead procurement activities of its participants. The Company will endeavor to work with Staff and have conversations about the potential impacts it identifies of power sellers aligning with evolving day-24 ahead markets (CAISO targeted to start in 2026 and SPP's Markets+ in 2027).

Staff notes that IPC relies on markets to supply a significant portion of energy and capacity during certain times of the year (short the market). Data from the PacifiCorp pre-filing workshops shows a trend of declining of liquidity in Mid-C market since the WEIM started in 2014. This declining liquidity is demonstrated by a trend of increased prices. It could be caused by the flight of sellers from the Mid-C to WEIM because perhaps the cost of transmission is high for Mid-C. Staff requests that IPC undertake an investigation of the declining liquidity of the Mid-C market and how it is positioned for the future considering that transmission investments are already made to connect to this market.

Energy Efficiency (EE):

15. In the lead up to the 2025 IRP, IPC should work with and provide workpapers to Staff that explore the costs and benefits of portfolio runs with more ‘low-cost’ bundles, such as bundles of measures costing below $30/MWh.

IPC agreed to work with Staff to support the expectation to bring forth EE bundles as a topic for discussion with the IRPAC for consultation. With the review and feedback of the IRPAC, Idaho Power will evaluate different EE bundle options and portfolio sensitivities in the next IRP. Staff agrees with the resolution.

Demand Response (DR):

16. IPC will engage Staff and stakeholders regarding DR block size during the development of the 2025 IRP.

IPC supports Staff's expectation of bringing the DR block size as a discussion topic in the IRPAC meetings during development of the 2025 IRP. Staff agrees with the resolution.