CHRIS BURDIN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
IDAHO BAR NO. 9810

Street Address for Express Mail:
11331 W CHINDEN BLVD, BLDG 8, SUITE 201-A
BOISE, ID 83714

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN	**CASE NO. IPC-E-23-23**
	COMMENTS OF THE COMMISSION STAFF

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission, by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On September 29, 2023, Idaho Power Company ("Company") filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting that the Commission issue an order acknowledging the Company's 2023 Integrated Resource Plan ("IRP").

The Company states that the 2023 IRP represents a comprehensive analysis of the optimal mix of both demand- and supply-side resources available to reliably serve customer demand and flexible capacity needs from 2024 to 2043. Application at 1-2.

The Company represents that the primary goals of the 2023 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within the Company's service area throughout the 20-year planning period (2024-2043); (2) ensure the selected Preferred Portfolio balances cost and risk, while including environmental considerations; (3) give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources; and (4) involve the public in the planning process in a meaningful way. *Id.* at 5.

The Company represents that it used the AURORA model to develop portfolios for the 2023 IRP. *Id.* at 7-8. The Company states that two notable trends emerged in the 2023 IRP, the vital nature of added transmission and the substantial downward trend in portfolio greenhouse gas emissions. *Id.* at 10.

The Company represents that it identified several key resources or potential projects to evaluate in additional detail, and the Company required the model to build portfolios both with and without each resource or project. *Id.* at 14. The Company states that these models with and without views include: (1) with and without the B2H project; (2) with and without different phases of the Gateway West projects; and (3) with and without specific Valmy Unit 1 and Unit 2 natural gas conversion assumptions. *Id.*

The Company represents that, based on its analysis, the Company selected a Preferred Portfolio identified in the 2023 IRP as "Valmy 1 & 2", referring to the portfolio's conversion of both Valmy units from coal to natural gas. *Id.* at 14-15. The Company states that this Preferred Portfolio is the least-cost, least-risk option that incorporates positive changes toward clean, low-cost resources without compromising system reliability. *Id.*

The Company's Preferred Portfolio adds 3,325 megawatts ("MW") of solar, 1,800 MW of wind, 1,453 MW of storage (four- and eight-hour batteries, as well as long-duration 100-hour storage), 360 MW of additional energy efficiency ("EE"), 340 MW of hydrogen ("H2"), 160 MW of new demand response ("DR"), and 30 MW of geothermal. *Id.* at 3.

Additionally, the Preferred Portfolio includes conversions of multiple coal-fired generation units to natural gas, showing the Company exiting coal entirely in 2030 and adding a net total of 261 MW of natural gas via coal conversions through 2043 (reflecting the addition of 967 MW of gas conversions and 706 MW of gas conversion exits, netting 261 MW of additional gas generation). *Id.*

The Company represents that, in total, the Preferred Portfolio adds 6,888 MW of incremental resource capacity over the next 20 years and includes the B2H transmission line beginning in July 2026 and three Gateway West transmission line segments phased in from 2029 to 2040. *Id.*

The 2023 IRP contains the Company's Near-Term Action Plan that reflects near-term actionable items of the Preferred Portfolio necessary to successfully position the Company to provide reliable, economic, and environmentally sound service to its customers into the future. *Id.* at 15.

The Company represents that the 2023 IRP incorporates prior recommendations it received concerning several issues, and the 2023 IRP provides additional analysis/discussion of those issues. *Id.* at 17.

On October 31, 2023, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 35974. The Commission granted intervention to Micron Technology, Inc. Order No. 36014. On December 1, 2023, a Notice of Parties was issued.

STAFF ANALYSIS

Staff recommends acknowledgment of the Company's 2023 IRP.

However, Staff believes that the Company's Preferred Portfolio may not be the least-cost portfolio. Staff has evidence that a portfolio containing more coal and gas ("fossil fuel") resources may be substantially less expensive than the Preferred Portfolio, albeit with an unknown level of risk. Therefore, Staff recommends that the Company perform additional analyses to validate the least-cost, least-risk portfolio and submit a supplemental report with the results.

Staff recognizes the significant time and effort the Company invested in developing this IRP and appreciates the vast amount of information compiled within it. The report has become increasingly complex and increasingly important as the types of analysis and results from the report guide and inform resource investments.

It is important to reiterate that the Commission's acknowledgment of the IRP should not imply that the results and resources included in the Preferred Portfolio infer prudence. Staff considers the resources included in the Company's Preferred Portfolio as "proxies" that the Company selected based on assumptions made at the time. Staff expects that the Company will select each resource at the time of acquisition by evaluating it against the range of alternatives that are available at that time and at current prices to obtain a determination of prudence.

Additional Staff comments and recommendations are organized in the following sections:

I. The Preferred Portfolio – Analysis and Recommendations;

II. The Near-Term Action Plan;

III. The Load Forecast;

IV. The Demand-Side Management Program;

V. The Seasons and Hours of Highest Risk;

VI. PURPA and Other Planning Assumptions; and

VII. Review of 2021 Staff Recommendations.

Staff recommendations are summarized at the end of this document in the STAFF RECOMMENDATION section.

I. THE PREFERRED PORTFOLIO - ANALYSIS AND RECOMMENDATIONS

The Preferred Portfolio is one of the primary results of the IRP process. It is the list of supply- and demand-side resources the Company believes will reliably meet the forecasted load over the next 20 years that are *least cost* and *least risk*. Because the Company uses the IRP portfolio results and methods of analysis as part of its justification for new resource projects, Staff examined the portfolio development process carefully, and found evidence that the Preferred Portfolio may not be the least-cost portfolio.

Staff explains its findings and recommendations in the following five sub-sections:

1. An overview of the resource selection process;
2. The Company's Preferred Portfolio;
3. Portfolio cost comparison;
4. Possible sources of portfolio bias; and
5. Recommendations.

1. Overview of the Resource Selection Process

The Company uses the AURORA Long-Term Capacity Expansion ("LTCE") modeling tool to select the resources for a portfolio. Application at 7-8. The Company inputs its forecasted system load, its existing resources, and a list of possible new resources into the LTCE model. For each resource, the Company inputs performance and cost characteristics. The Company also adds external constraints on the system that simulate likely future developments such as the addition of a transmission line or the exit of a generation resource. The forecasted system load is applied, and the model calculates the optimal mix of new resources needed to meet the load at a specified reliability standard. This resulting portfolio is then subject to a variety of pricing scenarios to determine which portfolio is the least-cost across most, or all, of the scenarios. Application at 8.

2. The Company's Preferred Portfolio

Over the IRP's 20-year time window the Company forecasted that system load would grow by 975 average megawatts ("aMW"), and the peak load would increase by 1,507 MW. IRP Appendix C at 16-17. The aMW growth represents the additional steady-state *energy* the Company must provide, and the peak load represents the amount of additional *capacity* the Company must provide. Table No. 1 displays this information.

Table No. 1: Forecasted Load Growth

Year	aMW	Peak Hr (MW)
2024	2024	3830
2043	2999	5337
Net Growth:	**975**	**1507**

To satisfy this increased load, the Company proposed a Preferred Portfolio containing a mix of new resources. Table No. 2 lists the net change for each type of resource over the 20-year time window. It also groups the resources into dispatchable resources, Variable Energy Resources ("VER"), Battery Energy Storage System ("BESS") resources, and Demand-Side Management ("DSM") resources.

Table No. 2: 2023 Preferred Portfolio

Resource	20-yr Net Change (MW)	Resource Category (MW)
Coal	-841	**Net Dispatchable:**
Gas	261	
Hydrogen	340	**-210**
Geothermal	30	
Solar	3325	**Net Variable:**
Wind	1800	**5125**
BESS	1453	**Net BESS: 1453**
Energy Efficiency	360	**Net DSM:**
Demand Response	160	**520**

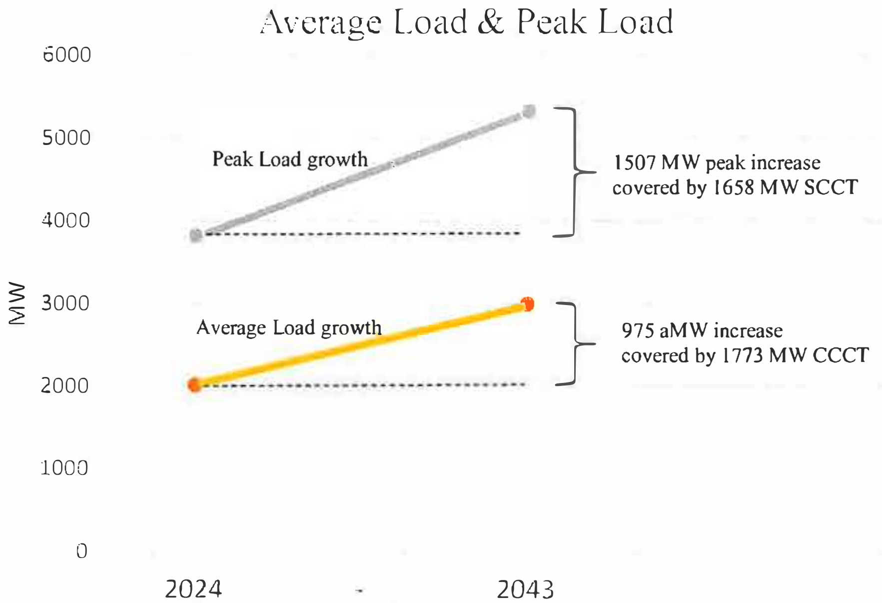
From these two tables, the big picture of the Company's proposal comes into focus. To satisfy the 975 aMW increase, the Company proposes to *reduce* its dispatchable resources, build *five times more* variable generation than the average load increase, and add 1,500 MW of BESS resources.

The Company's calculated net present value ("NPV") for this 20-year portfolio is $9.7 billion. Application at 11.

3. Portfolio Cost Comparison

To perform a high-level check on the cost-effectiveness of the Company's solution, Staff created a simplified model of the load requirement, and devised a hypothetical way to satisfy it using a combination of baseload and peaking dispatchable resources. The average load increase of 975 aMW can be hypothetically satisfied by a single Combined-Cycle Combustible Turbine ("CCCT") gas plant, adjusted for its Capacity Factor ("CF"). Similarly, the peak load increase of 1,507 MW can be hypothetically satisfied by a single peaking resource, a Simple-Cycle Combustion Turbine ("SCCT"), adjusted for its CF. Staff understands that this solution is simplistic, and multiple smaller dispatchable resources would be more likely, but it serves as a reasonable basis to compare order-of-magnitude costs. This model is illustrated in Figure No. 1 below.

Figure No. 1: Model of a Hypothetical Dispatchable Resource Portfolio



Using the cost inputs and operating assumptions from the IRP Appendix C, page 21, Staff calculated that this dispatchable portfolio would cost approximately $6.7 billion to build in the first planning year and operate for 20 years. This is $3.2 billion less than the NPV cost of the Preferred Portfolio.

To compare the two portfolio costs more fairly, Staff recalculated the VER and BESS portions of the Preferred Portfolio cost by using the same method as the dispatchable portfolio. By assuming both portfolios are fully built in year one, with 20 years of operating costs, the portfolios can be evenly compared. The results show the VER and BESS portfolio has an up-front cost estimate of $13.9 billion, more than $7 billion more expensive than the dispatchable portfolio. Staff calculations are shown in Table No. 3 below.

Table No. 3: 'Dispatchable' Portfolio Cost versus 'VER & BESS' Portfolio Cost

Resource	Reqd MW	Capacity Factor	Nominal MW	Total Capital ($/kW)	Capital Cost	Years of Ops	Fixed O&M ($/kW-month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M ($)[1]	Total Cost ($)	Portfolio Cost ($)
CCCT	975	55.0%	1773	$ 1,590	$ 2,818,636,364	20	$ 1.40	$ 595,636,364	$ 3.10	$ 529,542,000	$ 3,943,814,727	$ 6,739,155,758
SCCT	1507	90.9%	1658	$ 991	$ 1,642,944,994	20	$ 2.10	$ 835,564,356	$ 6.00	$ 316,831,680	$ 2,795,341,031	
Solar			3325	$ 1,222	$ 4,063,150,000	20	$ 1.90	$ 1,516,200,000	$ -	$ -	$ 5,579,350,000	$ 13,894,238,000
Wind (ID)			1800	$ 1,782	$ 3,207,600,000	20	$ 4.10	$ 1,771,200,000	$ -	$ -	$ 4,978,800,000	
BESS			1453	$ 1,600	$ 2,324,800,000	20	$ 2.90	$ 1,011,288,000	$ -	$ -	$ 3,336,088,000	

Note 1: To estimate the fuel costs, the CCCT is assumed to operate 100% of all hours, and the SCCT to operate 20% of all hours over the 20-year period.

Staff recognizes that this simplified cost comparison does not account for many factors such as project feasibility, gas pipeline limitations, gas price risk, and carbon price risk.

Nonetheless, the $7 billion portfolio cost difference calls into question the accuracy of the LTCE model and the Company's validation process.

4. Possible Sources of Portfolio Bias

Given the large cost difference between a dispatchable portfolio and the VER and BESS portfolio, Staff examined the LTCE modeling process and found several possible sources of potential bias. Staff organized these sources into three groups which are discussed in the following sub-sections:

a. Externally imposed constraints on the LTCE model;
b. Internal cost inputs and operating assumptions used by the model; and
c. Selection and optimization algorithms within the model.

a. External Constraints

Staff believes one of the most significant sources of bias came from the external constraints included in the model. Some of these constraints assumed completion dates of transmission lines, which Staff agrees are appropriate. However, others involved preferential assumptions about dispatchable resources. Among this latter group, are the following two constraints:

i. Forcing a coal exit or a conversion to gas at a predetermined time; and
ii. Forcing exits from gas at a predetermined time.

i. *Forcing a Coal Exit or a Conversion to Gas at a Predetermined Time*

First, the Company forced the LTCE model to choose between exiting coal and converting to gas in a predetermined year. The Company did not allow the model to consider continuation of coal operations, and the Company provided no economic basis for why it forced the choice nor for the timing of its choice. The Company told the model to select between exit or conversion for Valmy Coal Unit 2 in 2025, and Bridger Coal Units 3 and 4 in 2029. When asked for its reasons, the Company stated that the Valmy "exit date is based on alignment with the plant's co-owner and operator, NV Energy." *See* Response to Production Request No. 32. The Company also stated that the Bridger "exit and conversion timing are based on alignment with the co-owner and operator, PacifiCorp." *Id.* Staff is not aware of any economic justification for these decisions.

At a minimum, knowing the cost difference between fueling these plants with coal versus gas is useful in valuing any tradeoffs in risk between two fueling strategies. Staff believes there are compelling economic and reliability reasons to continue considering coal generation. Coal adds resource diversity which protects against price risk. In 2022, the average dispatchable price of coal was one-half of the price of gas-generated power, and one-third of the price of market-purchased power[1]. Furthermore, coal can be physically stored on site, which hedges against the supply-chain risk inherent in gas resources.

Staff recommends that the Company remove the coal-exit constraints from the LTCE to allow the model to make choices based on economics. Furthermore, Staff recommends that the Company provide justification for these exit-conversion actions in separate case filings.

ii. *Forcing an Exit from Gas at a Predetermined Time*

Second, the Company constrained the LTCE model to exit the converted-to-gas Bridger Units 1-4 in 2037. The Company's reason for this is that the "extension to 2037 aligns with the assumptions made by the co-owner and operator, PacifiCorp." *See* Response to Production Request No. 32. The Company also says that this date was based on "an update from *the assumed end of life* for these units of 2034 used in the 2021 IRP." *Id.* emphasis added. Although Staff agrees that the end of life for a resource is a valid constraint to build into the model, the Company's response suggests that the end-of-life for the Bridger gas plants is flexible. Staff recommends that the Company provide justification for setting the end of life to 2037. Also, Staff recommends that the Company build an option to extend the resource life at an estimated cost and then let the model choose whether to exit or extend.

b. Internal Cost Inputs and Operating Assumptions

A second category that may be causing the LTCE model to choose VERs and BESSs over other fueled dispatchable resources are the internal cost inputs and operating assumptions. Staff specifically discusses two examples:

[1] IPC-E-23-12, Staff Comments, Table No. 4

i. CFs and the Levelized Cost of Capacity ("LCOC"); and

ii. Interconnection costs.

i. *CFs and the LCOC*

The CF assumed for each resource is an important factor used to determine the contribution of each type of resource. CFs determine the percentage of a resource's nominal capacity that will be available to meet the peak load ("peak CF") and to produce energy ("energy CF"). The smaller the CF, the smaller the resource's contribution to peak load and energy provided to the system. Everything else being equal for two resources, a larger CF will be more cost-effective than a lower CF. For each resource, its peak CF and energy CF are typically different values.

First, the CF data was not easy to find in the report. Given the significance of CFs in determining cost effectiveness, Staff expected the IRP to prominently display the CFs for each resource. However, the peak CFs were not listed in the IRP and the energy CFs were listed in the last column of IRP Table 8.4. At Staff's request, the Company provided its assumed peak CFs as part of its response to Production Request No. 38. Staff recommends that the Company clearly display its assumed CFs for both peak and energy in future reports and discuss how it determined the values.

Second, Staff believes that some of the peak CFs and energy CFs are biased toward VERs and BESSs and away from fossil fuel resources. The Company proposed that CCCTs be modeled with an energy CF of 55 percent. IRP at 116, Table 8.4, emphasis added. However, the Company also stated that "According to the Energy Information Administration ("EIA"), a typical modern high efficiency Combined Cycle Combustion Turbine ("CCCT") plant capacity factor is about 65 percent." See Response to Production Request No. 84, emphasis added. This CF difference of ten percent is significant, especially for the CCCT, which Staff believes is a feasible baseload resource. The Company also used the same 55 percent CF for SCCTs.

Another example is the utility-scale solar resource, the Company assumed a peak CF of 27.7 percent. National Renewable Energy Laboratory ("NREL") data shows the value in southwest Idaho should be 25.8 percent[2]. Furthermore, as hundreds of MWs of solar are added

[2] https://atb.nrel.gov/electricity/2022/utility-scale_pv

to the system, Staff believes the peak CF will diminish. Therefore, it seems more reasonable for the Company to err conservatively and assume a value on the low side rather than the high side. Staff recommends that the Company meet with Staff to review the source of each CF assumption.

Third, Table 8.3 in the IRP presents the LCOC values for each resource based on its *nominal* capacity. The table does not adjust for the resource's peak CF. This gives the mistaken impression that VER and BESS are among the least expensive resources. If the LCOC values are adjusted by the peak CF, the results show that the lowest values belong to gas resources, and that wind resources are among the most expensive. To illustrate this point, Staff compiled Table No. 4 below, which compares the two LCOC values for each resource. The table is sorted by the CF-adjusted LCOC column.

Table No. 4: Comparison of Nominal LCOC with CF-Adjusted LCOC

Supply-Side Resources	Nominal LCOC ($/kW/mo.)	Peak CF	CF-Adjusted LCOC ($/kW/mo)
Clean Peaking Gas - Hydrogen Combustion Turbine	12	90.9%	13
Peaking Gas - Simple Cycle Combustion Turbine (SCCT)	12	90.9%	13
Baseload Gas - Combined Cycle Combustion Turbine (CCCT)	17	90.9%	19
Multi-Day Storage - Iron Oxide Battery (100 hour)	20	100.0%	20
Solar PV	7	27.7%	26
Danskin 1 Retrofit - SCCT to CCCT Conversion	26	90.9%	29
Medium Duration Storage - Li Battery (8 hour)	27	79.2%	34
Long Duration Storage - Pumped Hydro (12 hour)	36	100.0%	36
Short Duration Storage - Li Battery (4 hour) - Grid Distributed	15	38.5%	40
Short Duration Storage - Li Battery (4 hour)	17	38.5%	43
Biomass	54	100.0%	54
Geothermal	51	90.5%	56
Wind - WY	12	20.8%	58
Nuclear - Small Modular Reactor	82	98.1%	83
Wind - ID	14	15.5%	91

Staff recommends that the Company prominently display CFs and the CF-adjusted LCOCs in future IRPs so readers can better appreciate the tradeoffs between resources.

ii. *Interconnection Costs*

Interconnection costs are another area where Staff believes the Company's assumptions are biased toward VER and BESS resources.

When determining the up-front capital cost for each resource, the Company must include the cost to interconnect that resource to the grid. Factors that can affect this cost include the nominal power being added, the proximity of the resource to the nearest point of connection, and the available system capacity at the point of interconnection.

The Company did not include any interconnection cost data in the IRP except for a single column of normalized ($/kW) data in its Cost Input table. IRP Appendix C at 21. Staff asked for the full cost estimates for each resource in Production Request No. 36 and for additional information in Production Request No. 80.

The Company's responses revealed that the Company estimated a 300 MW solar resource and a 300 MW wind resource sited in Magic Valley would each cost $6.5 million to interconnect, for a normalized cost of $22 per kilowatt ("kW"). In contrast, a 100 MW retrofit of an existing gas plant in Magic Valley that is *already interconnected* would cost $9.4 million for interconnection upgrades, yielding a normalized cost of $94 per kW. This normalized cost is more than 400 percent more than for the VER resources. Staff was not convinced by the Company's explanation for this difference.

The Company also estimated the interconnection cost for a new 300 MW CCCT located near the existing Langley Gulch plant to be $41.8 million due to the need for transmission capacity upgrades. In contrast, a new 300 MW wind resource in Wyoming, with the same transmission needs as the CCCT, would only cost $6.5 million to interconnect. This yields a normalized cost of $140 per kW for the CCCT, and $22 per kW for the wind resource, a difference of 636 percent. Table No. 5 displays this information below.

Table No. 5: Comparison of Interconnection Costs

Resource	*Nominal Capacity Assumed for Cost Estimate*	Cost Assumption Notes	Local Interconnection Assumption	Cost Estimate	Cost Estimate (per kW)
Natural Gas *Combined Cycle Combustion*	300	Treasure Valley Area	Connection to 230-kV Bus *Transmission Line Upgrades Required*	$41,862,000	$140
Danskin 1 Retrofit *SCCT to CCCT Conversion*	100	Mountain Home Area	Connection to 230-kV Bus	$9,370,000	$94
Solar PV *Utility-Scale 1-Axis Tracking*	300	Mountain Home Area	Connection to 230-kV Bus *Local Transmission Upgrades Required*	$6,500,000	$22
Wind - Wyoming	300	Within 5 Mi of Jim Bridger	Connection to 345-kV Bus	$6,500,000	$22
Wind - Idaho	300	Magic Valley Area	Assumes 345-kV Connection	$6,500,000	$22

Staff believes that the interconnection cost data is biased toward VER resources and away from fossil fuel resources. Staff recommends that the Company meet with Staff to review the interconnection cost estimates and attempt to standardize the assumptions for each resource. Staff also recommends that the Company display its interconnection assumptions more plainly.

c. The Resource Selection and Optimization Algorithms

A third source of possible bias in the LTCE model is the model's resource selection algorithm. Staff's concern is that the LTCE model may not select large resources when the incremental load deficit is small.

For example, if a 100 MW load deficit is forecast for a given year, will the LTCE model select a 300 MW resource, or will it select a 100MW resource, with everything else being equal? If it will always select the more appropriately sized 100MW resource, then the size of the selectable resources can become a source of bias. The Company set the baseload gas CCCT resource to be 300 MW, and the peaking gas SCCT resource to be 170 MW, but the VER resources are each set at 100 MW.

Another hypothetical example occurs if the load forecast shows small deficits accruing over several years. For example, if the load deficit grows by 100 MW in years one, four, and seven, will the LTCE model select 100 MW resources for each year, or will it see that the collective deficit in 7 years will be 300 MW and analyze if a 300 MW resource might be more economical?

Although these are hypothetical examples, Staff notes that most of the IRP portfolio results show that the LTCE model selected a new gas resource only when a large fossil fuel resource exited. In other words, the exit of a large fossil fuel resource created a load deficit large enough to *allow* the model to select the CCCT resource, and the model then selected it. This observation also implies that the model may view the CCCT resource as more economical than VER resources when the CCCT resource is available.

Staff recommends the Company meet with Staff to confirm the algorithm logic and run tests to observe how the model works.

5. Recommendations

In summary, Staff believes that the IRP's Preferred Portfolio may not be the least-cost portfolio. A portfolio with a larger share of dispatchable fossil fuel resources appears to be substantially less expensive. Although Staff is unable to assess many of the risks associated with a dispatchable resource portfolio, Staff believes dispatchable resources can be more reliable than VERs and enhance system reliability. However, Staff also recognizes that fueled carbon-emitting resources also have different risks.

Because the Company uses IRP assumptions and results as part of its justification for future resource projects, Staff believes that the Company should resolve some of these concerns through additional analysis and through a supplement to the IRP. Staff's proposed process, and other related recommendations, are outlined below.

a. Prepare an IRP Supplement

First, Staff recommends that the Company establish a meeting of interested Parties. The meeting should aim to resolve the questions about various cost inputs and the LTCE model selection algorithms.

Second, Staff recommends that the Company re-run its most prominent existing scenarios but with the following changes to the baseline planning assumptions:

i. Modify the forced coal exits to allow for coal continuation or conversion to gas for Valmy and Bridger; and
ii. Justify the Bridger end-of-life in 2037 and modify the LTCE model to allow a service-life extension option.

Third, Staff recommends that the Company cost test at least one new portfolio that has a preponderance of dispatchable fossil fuel resources.

Last, Staff recommends that the Company submit a supplement to the existing IRP that reflects the conclusions of this effort. The supplement should be subject to comments from the Parties.

b. Provide Separate Justification for the Conversion or Exits of Valmy and Bridger

Staff also recommends that the Company submit separate filings for each proposed conversion or exit of Valmy and Bridger. These actions carry significant cost and risk implications for ratepayers, and due diligence is needed to assess the prudence.

c. Implement Changes to Future IRPs

Finally, Staff recommends that the Company make the following changes to future IRPs:

i. Clearly display the assumed peak and energy CFs for each selectable resource. Also, discuss how the values were determined;
ii. Prominently display both nominal LCOCs and CF-adjusted LCOCs for each selectable resource. Discuss which values are used by the LTCE model; and
iii. Plainly display the underlying assumptions and estimates used to determine interconnection costs for each selectable resource. Standardize the assumptions unless there is a clear and compelling difference.

II. THE NEAR-TERM ACTION PLAN

The Company requested that the Commission acknowledge the Company's Near-Term Action Plan. Staff recommends that the Commission refrain from doing so and limit itself to only acknowledging the overall 2023 IRP.

Staff notes that the Near-Term Action Plan consists of eight action items, some of which derive from the Preferred Portfolio. Since Staff believes the Preferred Portfolio may not be least-cost, Action Plan items that are based on the portfolio may not be appropriate. Accordingly, Staff provides the following comments for each of the Company's proposed actions.

a. Boardman to Hemingway ("B2H") Online by Summer 2026

The Company provided an updated September 2023 cost estimate for the planned transmission project, which was 26 percent higher than the cost estimate provided in the

Company's Certificate of Public Convenience and Necessity ("CPCN") filing in January 2023.[3] The increase was largely due to preliminary construction bids. The Preferred Portfolio relied on the completion of B2H in July of 2026, with construction estimated to start by the end of 2023.

In November 2023, the Company stated that the B2H construction start was delayed into the first half of 2024.[4] As part of the Company's alternative portfolios, a November 2026 B2H portfolio was created with an estimated cost of $21 million more than the Preferred Portfolio. Staff is concerned about the schedule delays and continued cost growth for the B2H project.

b. Continue Exploring the Company's Participation in Southwest Intertie Project – North

The Company provided minimal information about the Southwest Intertie Project – North ("SWIP-N") project within the 2023 IRP. The Company is exploring 500 MW of south-north capacity from the transmission line. *See* Response to Production Request No. 18. The Company's participation in "[t]he SWIP-N project could enable the Company to access the liquid desert southwest market during winter, while avoiding more costly internal resource builds to meet the forecasted growth in peak winter energy demands." *See* Response to Production Request No. 50. The Company stated it was in active negotiations regarding this project; therefore, the 2023 IRP did not provide cost assumptions for the Company's involvement with the project. *Id.* Additionally, SWIP-N was not included in any of the Company's portfolios.[5] In the 2021 IRP, the Company evaluated the SWIP-N transmission project with an estimated 200 MW capacity with an estimated cost of $133 million with an in-service date of pre-summer 2025.[6] Due to lack of transparency of the Company's participation in SWIP-N within the 2023 IRP, Staff recommends the next IRP provide more detailed information about the scope and cost of the project.

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[3] *See* Company's Confidential Attachment 1 – B2H Cost Breakdown.

[4] https://www.newsdata.com/clearing_up/clearing_it_up/industrial-demand-is-driving-growth-across-idaho-powers-territory/article_6d5b6f2e-8961-11ee-b600-9364c84be9dc.html#:~:text=Construction%20on%20the%20500%2DkV,the%20first%20half%20of%202024. (last visited January 31, 2024).

[5] *See* Appendix C at 42-71.

[6] 2021 Integrated Resource Plan at 89.

c. Install Cost Effective Distribution-Connected Storage from 2025 to 2028

The Company did not provide details on this action item within the 2023 IRP. However, in response to Production Request No. 12, the Company stated, "At this time, Idaho Power does not have any distribution-connected storage projects planned for 2025 and beyond but is constantly evaluating various local needs to see if distribution-connected storage could be a cost-effective solution." Additionally, the Company referenced Table 5.1 in the 2023 IRP of examples of targeted grid storage with capacities between two to four MW. Staff recommends that the Company provide additional analysis for any distribution-connected battery projects it is planning in future filings, such as a general rate case. Staff also recommends that the Company clarify how it selects between distribution-connected and transmission-connected battery projects in future IRP filings.

d. Convert Valmy 1 & 2 from Coal to Natural Gas by Summer 2026

The Company selected to convert both units of Valmy 1 and 2 from coal to natural gas by the Summer of 2026 within its Preferred Portfolio. The Company exited Unit 1 as coal in 2019 and plans to exit Unit 2 as coal by the end of 2025. Staff reiterates its recommendation for the Company to submit separate filings for each proposed conversion or closure of Valmy and Bridger.

e. Acquire up to 1,425 MW of Combined Wind and Solar in 2026-2028

This action is based on the Preferred Portfolio resource selections, which Staff believes is insufficiently validated. Staff reiterates its recommendation that the Company provide a supplemental filing with additional analysis as described in the Preferred Portfolio section.

f. Explore a 5 MW Long-Duration Storage Pilot Project

The Company's Preferred Portfolio includes a total of 1,453 MW of storage, including 100-hour storage. In the Company's response to Production Request No. 11, the Company said it was still exploring long-duration storage options, such as a 100-hour iron-air battery. The Company stated that it would seek Commission approval with a formal filing if it decided to move forward with such a project. Staff agrees with this course of action.

g. Include 14 MW of Western Resource Adequacy Program ("WRAP") Capacity

In Order No. 35920, the Commission ordered the Company to include available information about the WRAP's costs, benefits, as well as lessons learned by the Company in its IRPs. Following the Company's expected binding date into WRAP, 14 MW is included in the Company's Capacity Position starting in 2027. *See* Response to Production Request No. 19. Staff believes that the Company has complied with Order No. 35920.

h. Gateway West ("GWW") Phase 1 Online by End of 2028

The Company modeled additional transmission capacity within the Preferred Portfolio. GWW Phase 1 consists of two transmission line segments and one substation. The Company has a one-third permitting interest in Midpoint-Hemingway #2 (Segment 8) and Midpoint-Cedar Hill (Segment 10) 500-kilovolt ("kV") transmission lines. This project also includes the Mayfield 500-kV substation. The Company believes that its participation in this project will enable 1,000 MW of incremental resources on the system. Like other similar transmission projects, such as B2H, there are risks of schedule delays and cost growth. Staff is concerned that the assumed availability date may be delayed, which in turn will also affect the availability of renewable energy in the Preferred Portfolio.

III. THE LOAD FORECAST

The Company builds its load forecast with a probability range. The 50^{th} percentile load forecast ("P50") represents the most probable load. The 70^{th} percentile load ("P70") has a greater magnitude than the P50 load, and has a 70 percent chance the actual load will be lower, and a 30 percent chance the actual load will be higher.

The Company used a P50 load forecast and a more stringent reliability target than the industry standard in its 2021 IRP analyses. For the 2023 IRP, the Company adopted the industry standard reliability target, but used a P70 load forecast. Staff identified two issues as a result of the Company's decisions: (1) a lack of proper justification for using P70 load forecast for reliability purposes; and (2) potential inflated expected energy costs for rates and avoided costs by using the higher load forecast.

1. Justification for the P70 Load Forecast

Staff believes that the Company failed to provide sufficient evidence that the P70 load forecast was the appropriate choice. Staff recommends that the Company meet with Staff during the next IRP cycle, to discuss how to provide reasonable and adequate evidence in its next IRP to determine and verify an anticipated peak load forecast used to ensure sufficient resources for purposes of reliability.

The Company used a P70 peak load forecast to determine the amount of resources needed to meet a 0.1 event-days per year ("1-in-10") Loss of Load Expectation ("LOLE") reliability target, which is considered an industry standard. This was a change from using a P50 peak load forecast and a 0.05 event-days per year ("1-in-20") LOLE threshold from the 2021 IRP[7]. In that case, Staff stated that "a reliability target should be determined independent of the Company's loads and resources, and instead should be a policy decision based on the tolerance of customers and the public to costs, risks, and other impacts related to electricity outages." Case No. IPC-E-21-43, Staff Comments at 9. In this case, when asked how and why the Company determined that the P70 peak load forecast was the right level to use for its planning case, the Company stated that it was selected in combination with 1-in-10 LOLE threshold, because the annual capacity position determined under this assumption was similar to that determined under the assumption of a P50 peak load forecast and a 1-in-20 LOLE threshold from the 2021 IRP. *See* Response to Staff Production Request No. 21.

Although using a higher percentile of the peak load forecast is one way to ensure enough capacity margin is included in its portfolios for purposes of meeting its reliability target, Staff does not believe that using a capacity position as a reference point that was based on an inflated LOLE target is proper justification for choosing the proper percentile of load. Staff recommends the Company meet with Staff early in the next IRP cycle to discuss methods to determine and verify the percentile of load that is appropriate to meet its reliability target in the next IRP.

2. Cost Implications from using the P70 Load Forecast

While analyzing the 2023 IRP, Staff realized that the Company's use of the P70 load forecast had the potential to inflate the variable energy costs used to value DSM benefits and customer rates that utilize outputs from the IRP. Although a P70 forecast may be appropriate for

[7] A 1-in-20 LOLE is more stringent than a 1-in-10 LOLE.

sizing capacity needs, as discussed above, because the magnitude of the P70 was greater than the P50, the modeling algorithms require higher-than-average energy costs. This yields higher costs for every portfolio and could potentially drive the AURORA-generated market prices higher, which flow into various customer rates and the cost-effectiveness tests used in the Company's DSM programs.

Staff recommends that for future IRPs, if the Company determines its Preferred Portfolio by using something other than the P50 load forecast, it should still use the P50 loads in its dispatch model to calculate IRP portfolio energy costs and marginal avoided costs. Staff also recommends that for tariffs that are affected by avoided cost calculations (i.e. Lamb Weston, Brisbie, Schedule 20), separate dockets should be filed, and Staff will analyze the Company's cost bases in those dockets.

IV. THE DEMAND-SIDE MANAGEMENT PROGRAM

The DSM program is fundamentally connected to the IRP. Staff discusses changes to the DSM program and avoided cost implications in the two following sub-sections.

1. Program Planning

In meetings with Staff, and at its August Energy Efficiency Advisory Group ("EEAG") meeting, the Company implemented changes in this IRP for its DSM program planning. The Company's previous policy was to plan and evaluate its DSM programs using avoided cost averages provided by the most recently *acknowledged* IRP. After discussions, the Company is now changing its policy to use avoided costs provided by the most recently *filed* IRP. Staff believes that this change will allow DSM programs to reflect the Company's system and planning process more closely.

Under the previous policy, avoided costs from the most recent IRP cannot be used to plan DSM programs because the IRP is not typically acknowledged until the following year. Instead, the Company must rely on avoided cost data that is two years out of date to plan a program occurring the following year, creating a three-year lag.

Under the updated policy, changes in avoided costs will be recognized in a more timely manner. *See* Response to Production Request No. 52. By using the most recently *filed* avoided costs, DSM program planning will more closely reflect the most current data.

2. Avoided Costs

Staff is concerned that the 2023 IRP avoided costs are based on the Preferred Portfolio and the P70 load forecast, and therefore the avoided costs may be incorrect.

a. Preferred Portfolio Impact

As described in the Preferred Portfolio section, Staff believes that the Company's cost input assumptions may be biased toward VERs and away from fossil fuel resources. Adjustments may be necessary for the least-cost, dispatchable, selectable resource (currently the SCCT), which would affect the avoided cost of capacity. Similarly, a different Preferred Portfolio could change the avoided cost of energy.

Staff recommends that the Company not use the 2023 IRP DSM avoided costs included in this filing and reassess the avoided costs as part of the recommended supplemental filing. For this IRP cycle, the Company should consider the supplemental IRP filing "the most recently filed IRP". If the Company has not filed a supplemental IRP by the time the Company either evaluates its 2024 DSM program or conducts 2025 DSM program planning, the Company should use the DSM avoided costs from its 2021 IRP.

b. P70 Impact

As described in the P70 load forecast section, the P70 load forecast skews the DSM avoided costs. In its supplemental response to Production Request No. 67, the Company provided a comparative analysis of the DSM avoided cost averages based on the P70 and P50 forecasts. Staff reviewed the analysis and agreed with the Company's conclusion that, while the P70-based avoided costs are higher, the increase is "approximately 1 percent ...but actual variance changes by year and time period." *See* Supplemental Response to Production Request No. 67 at 3. Staff recommends that the Company use the P50 load when determining avoided costs in the next IRP.

V. SEASONS AND HOURS OF HIGHEST RISK

Through the proceedings of Case No. IPC-E-23-11 and IPC-E-23-14, an increased emphasis was placed on how the Company determines the highest risk seasons and hours. The highest risk seasons and hours, as determined in the IRP, are used as a basis for the Export Credit Rate, Time-of-Use rates, the dispatch parameters of DR programs, and the load shapes of EE benefits. In Order No. 36048, the Commission directed that any updates to the summer season or the hours of highest risk be considered in a separate docket or in a general rate case. Order No. 36048 at 6. In the sections below, Staff conducted a thorough review of the methodologies and results of the Company's seasons of highest risk and hours of highest risk. The Company's modeling shows a summer season from June 1 - September 15, a winter season from Nov 1 – February 28/29, and hours as detailed in Table No. 6.

Table No. 6: Comparison of Summer and Winter Hours of Highest Risk

Season	2021 IRP Hours	2023 IRP Hours
Summer High-Risk	4pm - 11pm	8pm - 10pm
Summer Medium-Risk	12pm - 4pm / 11pm - 12pm	6pm - 8pm / 11pm - 12pm
Winter High-Risk	N/A	7am - 11am / 6pm - 9pm
Winter Medium-Risk	6am - 9am / 5pm - 8pm / 8am - 11pm	11am - 1pm / 5pm - 6pm / 9pm - 10pm

In general, the methods supporting the seasons and hours of highest risk are reasonable. However, Staff does have concerns with certain assumptions and practices and does not recommend updating the seasons or hours of highest risk in conjunction with this report.

1. Seasons of Highest Risk

Staff analysis of the Company's method for determining seasons of highest risk suggests that, in general, the approach is reasonable. However, Staff is concerned with a decline of risk hours in the months of June, September, and February and the large percentage of total risk hours catching lower risk hours in these months. The Company describes its method as grouping the top 90 percent of total risk hours by the day and month in which they occur. Appendix C at 92; also *see* Response to Production Request No. 5. Staff was able to verify the calculations using data provided in the Company's response to Production Request No. 3. Staff believes that while the top 90 percent of total risk threshold does capture the seasons of highest risk, the large percentage may contribute to an unfocused perspective of system risk. This is supported by the Company's response to Production Request No. 74, Attachment 1, which shows sporadic risk hours in October and in January, depending on the test year. Notably, this analysis does not include any risk hours in February. Finally, the Company states that it did not conduct analysis of other top percentages of total risk thresholds. *See* Response to Production Request No. 69. In any future cases that use this method of analysis, and in the Company's next IRP, Staff recommends the Company provide analysis that supports the percentage of total risk hours threshold used to select seasons of highest risk. The selected percentage should balance capturing the critical risk seasons while providing a focused perspective on when those seasons occur. Additionally, the analysis should evaluate why other percentages (e.g., 70 percent or 80 percent) are or are not appropriate for determining the season of highest risk.

2. Hours of Highest Risk

Staff analysis suggests that the Company's method for determining hours of highest risk is generally reasonable, but the analysis should include BESS resources. The Company describes its method for determining the hours of highest risk as grouping the top 50 percent of total risk hours for each month in a season by the hour in which they occur. Appendix C at 93; also *see* Response to Production Request No. 7. Additionally, in its response to IPC-E-23-11 Production Request No. 252, the Company states that it excludes BESS and DR resources because of their limited dispatchability and uses this analysis to inform TOU rates. Staff disagrees with the Company's practice of excluding BESS and DR resources from the analysis. Additionally, Staff believes that the top 50 percent of total risk hours in a month may not provide a clear perspective on the hours of highest risk.

The Company's preferred portfolio shows the system currently has 304 MW of BESS resources with an additional 323 MW to be added by 2025. IRP at 6, 51, and 52. The LTCE model selects these resources to address capacity and reliability positions. Additionally, unlike a traditional generation system, BESS resources represent a load to the Company's system greater than their nameplate capacity due to round-trip efficiency losses. This load from charging batteries contributes to risk and should be accounted for when modeling hours of highest risk. Staff believes that, while excluding BESS and DR resources provides valuable insight, excluding these resources does not accurately represent risk to the Company's system and devalues solar resources.

Staff and Company analysis on hours of highest risk suggests that by excluding BESS and DR resources, the high-risk hours are concentrated in later hours when solar systems are no longer producing. Including BESS and DR resources reduces and spreads the risk across a much larger timeframe consistent with current high-risk hours. If the Company were to file to update its highest risk hours based on the timing presented in the IRP, customer-owned generation systems would be adversely impacted as the majority of exporting systems are solar and are not granted the same rate stability as Public Utility Regulatory Policies Act ("PURPA") systems or Company-owned systems.

Staff believes that while the top 50 percent of total risk threshold captures the seasons of highest risk, the large percentage may contribute to an unfocused perspective of system risk. This is supported by the Company's analysis in its response to Production Request No. 77, Attachment 1. For the summer season, the analysis shows discontinuous occurrences of highest risk between 3 am and 8 am. For the winter season, the analysis shows occurrences of highest risk hours during all hours of the day. Similar to the seasons of highest risk, the Company states that it did not conduct analysis of alternate risk thresholds in its response to Production Request No. 71. Staff recommends that the Company maintain its current hours of highest risk. In any future case that uses this analysis and, in the Company's next IRP, Staff recommends the Company provide analysis that supports the percentage of total risk hours threshold used to select hours of highest risk. The selected percentage should balance capturing the critical risk hours while providing a focused perspective on when those hours occur within a given season. Additionally, the analysis should evaluate why other percentages are or are not appropriate for determining the hours of highest risk.

VI. PURPA AND OTHER PLANNING ASSUMPTIONS

Staff recommends that the Company adjust its PURPA assumptions in future IRPs. Also Staff provides comments regarding other planning assumptions.

1. PURPA

Staff identified the following issues associated with forecasted PURPA development in the 2023 IRP.

a. The Company's justification for excluding forecasted PURPA projects in its base planning conditions is not reasonable;
b. The Company did not use the most recent data in its PURPA trend analysis; and

c. The results of the PURPA trend analysis were applied in New Forecasted PURPA Scenario only after the Action Plan window in 2029.

Staff recommends that the Company conduct a PURPA trend analysis that includes the most recent data and apply the analysis results in the base planning conditions starting the first year of the planning horizon in the next IRP.

a. New PURPA Resources Should Not Be Excluded from Baseline

First, the Company did not include any forecasted PURPA projects in its base planning conditions in the 2023 IRP, because there has not been any new IRP-based PURPA projects in Idaho over the past five years. 2023 IRP at 128; also *see* Response to Staff Production Request No. 27. Staff believes this justification is not reasonable, because the Company should not focus only on IRP-based PURPA projects in Idaho without considering Surrogate Avoided Resource-based ("SAR-based") PURPA projects in Idaho and PURPA projects in Oregon. For example, since 2018, there have been three new SAR-based projects in Idaho and five new PURPA projects in Oregon. *See* Response to Staff Production Request No. 27 (b) and (c).

b. Use the Most Recent PURPA Data

Second, the Company conducted a 10-year PURPA trend analysis from 2012 through 2021. IRP at 128. However, the most recent data from 2022 and 2023 were not used in the analysis. Staff believes this data should not be excluded in the analysis. Staff recommends that the Company include the most recent data in future analyses.

c. The New Forecasted PURPA Scenario

Third, the results of the PURPA analysis were applied in the New Forecasted PURPA Scenario only *after* the Action Plan window in 2029. The 10-year analysis showed an average of 57 MW of new PURPA projects each year. *Id.* at 128. However, this trend was only applied after the Action Plan window. Staff believes that this defeats the purpose of exploring different future scenarios, which is to "compare the resources selected in the Preferred Portfolio, developed under planning constraints and conditions, to resources selected in other possible scenarios." *Id.* at 126. The IRP further states that "[t]his is especially useful for near-term resources. The goal of the comparisons is to understand how resources would need to shift if various scenarios materialized." *Id.* at 126. If a similar PURPA scenario is run in future IRPs, Staff recommends that PURPA resources be brought on line starting the first year of the planning horizon.

2. Planning Assumptions

Staff adds the following comments about other planning assumptions used in the 2023 IRP.

a. BESS Degradation

While reviewing prudence of BESS capital investments in Case No. IPC-E-23-11, Staff did not believe the Company included the full cost of a BESS over its lifecycle in comparison with other resource alternatives due to battery degradation. Staff could not determine if this oversight was addressed in the 2023 IRP. To ensure BESS resources are evaluated on an equivalent basis with other resource alternatives, Staff recommends the Company include degradation incremental costs and be able to reflect them explicitly in its cost analysis in its supplemental filing, future IRPs, and in future prudence reviews.

b. Electric Vehicle ("EV") Adoption

The Company provided minimal information on the planning assumption used for EV adoption within the 20-year planning horizon. The Company assumed that EV adoption will have a compound annual growth rate of 5.6 percent, an overall twenty-fold increase from 2022 to 2043[8]. Staff believes this assumption is reasonable based on the Idaho forecast data from Moody's Analytics and trend growth established using Department of Energy's Annual Energy Outlook forecast applied to Idaho's EV share of total vehicle registrations.

c. Customer Generation Adoption

The Company also provided minimal information on the planning assumption used for customer generation adoption. For the Residential Class, the Company forecasted a rapid growth trend until 2033, then a decreased growth trend until end of 2043. For the Irrigation Class, the

[8] *See* the Attachment 1 in the Company's response to PR 16.

Company forecasted a rapid growth trend until 2029, then forecasted a decreased growth trend until end of 2043. The Company used terminal saturation forecasts for the Residential class until 2034 and the Irrigation Class until 2029, then switched to month-over-month growth due to the Company determining the terminal saturation growth trend exceeded reasonable growth. *See* Company's Response to Production Request No. 47. For the Commercial Class, the Company forecasted a declining growth trend year-over-year. The Company did not forecast additional customer generation adoption for the Industrial Class due to current limited participation. Staff believes the assumption for the initial rapid growth trend is reasonable based on current available incentives. Additionally, Staff believes the leveling of the adoption rate in later years of the planning horizon is reasonable as it reflects customer generation saturation in the classes. Staff recommends the Company monitor the Residential and Irrigation Class adoption rates as a result of changes to the Company's Export Credit Rate starting in 2024 and adjust the IRP forecast as necessary based on actual adoption rates.

d. Transmission Capacity

Within the IRP, the Company modeled increased transmission capacity within its Preferred Portfolio. Staff has the following comments on the assumed transmission capacity availability.

i. B2H

The Company modeled the transmission capacity of 750 MW west-to-east and 182 MW east-to-west in the base case portfolio assumptions. *See* Response to Production Request No. 51. Staff believes this assumption is reasonable as B2H has been permitted, contracted, and construction is soon to begin.

ii. GWW Phases

The Company included the three phases of GWW to support resource additions in its Preferred Portfolio. The Company assumed GWW Phase 1 capacity in 2029, GWW Phase 2 capacity in 2031, and GWW Phase 3 capacity in 2040. The Company assumes both Phase 1 and Phase 2 will each provide 667 MW of capacity, while enabling 1,000 MW of incremental resources on the system. The Company anticipates it will own all capacity in Phase 3, which will enable 2,000 MW of incremental resources. Although the Company modeled the transmission capacity, the Company does not have formalized contracts with PacifiCorp for construction and capacity allocation of the GWW phases. Staff reiterates its concern for likely transmission project construction delays, underestimation or inflation of construction costs, and availability of capacity.

iii. Capacity Benefit Margin ("CBM")

The Company reduced the planning capacity of an original 330 MW energy emergency transmission to 200 MW in summer and to 0 MW in the winter. The Company cites that the planning reduction is due to continued transmission market limitations in both seasons. However, the Company will continue to operationally set aside 330 MW of transmission capacity for CBM. IRP at 82. Staff believes it is reasonable to lower the CBM capacity from the 330 MW level due to the transmission market limitations in the summer and the wholesale energy market depth in the winter.

VII. COMPLIANCE WITH PRIOR ORDERS AND REVIEW OF 2021 RECOMMENDATIONS

Lastly, Staff reviewed the 2023 IRP for its compliance with Commission Order No. 35837 from Case No. IPC-E-23-17, and for its alignment with Staff recommendations from the 2021 IRP.

1. Compliance with Order 35837

To ensure on-time submittal of the 2025 IRP, Order No. 35837 directed the Company to submit a plan and schedule in the 2023 IRP filing to ensure timely delivery of the 2025 IRP. Staff concurs that the Company complied with the Order. The 2023 IRP proposes a reasonable timeline for the 2025 IRP, with a final filing date of June 2025. The schedule reflects that the Company will collect model input data, hold 8 to 12 IRP Action Committee meetings, conduct a public review, and then file the IRP.

Staff notes that the 2025 IRP schedule could be in jeopardy due to the supplemental 2023 filing recommended herein. Staff recommends the Company plan accordingly to ensure that it files the 2025 IRP on time.

2. Review of Staff's 2021 IRP Recommendations

Staff reviewed the 2023 IRP for its alignment with Staff's 2021 IRP recommendations.

a. Extreme Weather LOLE

In the 2021 IRP case, Staff recommended the use of a 1-in-10 LOLE in the 2023 IRP analysis instead of a 1-in-20 LOLE. Staff believed that the LOLE should be set as a matter of public policy, and the Company should account for weather events and variability elsewhere in the model's input assumptions. The 1-in-10 LOLE threshold was more consistent with the industry standard and the Company's historical practices.

Staff concurs that the 2023 IRP analysis used the 1-in-10 LOLE threshold.

b. Market Access

Staff recommended that the Company only include market access backed by firm transmission reservations in its load and resource balance for the 2023 IRP. Staff believed that relying on market access without firm transmission exposes the Company to reliability risks.

Staff concurs that the 2023 IRP adhered to this recommendation. However, Staff notes that CBM is included in the Load and Resource Balance ("L&RB"), but it does not have any firm third-party reservation. Staff discussed this in detail in Staff Comments in Case No. IPC-E-23-27. In the next IRP filing, Staff recommends that the Company provide justification for why the CBM should be included in the L&RB.

c. Model Validation and Verification

Staff recommended a comprehensive analysis plan to verify and validate the models used in the 2023 IRP analysis. Staff's request was for the Company to describe the purpose of the test, how the test was conducted, and the results of the test.

Staff concurs that the Company generally followed the requested validation and verification process. However, Staff does not believe that the verification and validation tests adequately tested the model output, as explained in the Preferred Portfolio section.

d. Evaluating Risks and Inaccuracies

Staff recommended that the Company evaluate the risks and inaccuracies from employing a single benchmark year (2023) to determine the LOLE-based Planning Reserve Margin ("PRM"). Staff was concerned about the accuracy of the reliability model used to verify the portfolios by using a static PRM value over the entire planning period.

Staff concurs with Company's implementation of LOLE-based seasonal PRM calculations performed at different points along the planning horizon for the AURORA LTCE model. The Company provided the AURORA model with independent summer and winter PRM values to account for seasonal fluctuation. In addition, the Company updated both PRM values in select years to capture the effects of significant changes in the resource buildout.

e. Development of a Bridger Exit Agreement

Staff recommended that the Company develop a Bridger exit agreement with PacifiCorp that would determine the potential cost of extending or exiting operations. The exit costs could then be used in the 2023 IRP analysis to accurately assess the costs and benefits of different coal exit dates.

At the time of the 2023 IRP filing, Staff believes that the Company had not developed an exit agreement. However, Staff has indications that the Company is working with PacifiCorp on the matter. Staff reiterates its recommendation (from the Preferred Portfolio section) that the Company provide separate filings for each proposed conversion or closure of Valmy and Bridger.

STAFF RECOMMENDATION

Staff recommends that the Commission acknowledge the 2023 IRP. In addition, Staff has identified several other recommendations as outlined below.

1. Staff recommends that the Commission order the Company to submit a supplemental filing for the 2023 IRP that addresses the Preferred Portfolio concerns. This process should include the following:
    a. Establish a meeting of interested Parties to resolve concerns about model cost inputs and the selection algorithms. Include BESS degradation incremental costs;

b. Re-run the most prominent existing scenarios with recommended changes to the baseline planning assumptions;
   i. Modify the forced coal exits to allow the model to choose between coal continuation, exit, or conversion to gas, for Valmy and Bridger;
   ii. Eliminate the forced exit from Bridger in 2037. If the Company justifies an end-of-life closure, allow the model to choose between an exit or a service-life extension;
c. Cost test at least one new portfolio that has a preponderance of dispatchable fossil fuel resources;
d. Confirm the 2023 DSM avoided cost data; and
e. Allow for comments from Parties on the Supplement.

2. Staff recommends that the Commission order the Company to submit separate filings for approval of each proposed conversion or exit of Valmy and Bridger.

3. Staff recommends the following changes to future IRPs:
   a. Display the assumed peak and energy CFs for each selectable resource;
   b. Display both nominal LCOCs and CF-adjusted LCOCs for each resource;
   c. Display the underlying estimates used to determine interconnection costs;
   d. Provide more detailed information about the scope and cost of the SWIP-N project;
   e. Clarify how the Company selects between distribution-connected and transmission-connected battery projects;
   f. Meet with Staff to determine the method for selecting the load probability profile;
   g. Use the P50 in the dispatch model to calculate IRP portfolio costs and IRP marginal avoided costs;
   h. Include BESS and DR resources in analysis of seasons and hours of highest risk;
   i. Provide analysis that supports the percentage of total risk hours threshold used to select *seasons* of highest risk;
   j. Provide analysis that supports the percentage of total risk hours threshold used to select *hours* of highest risk;

k. Conduct a PURPA trend analysis that includes the most recent data and apply the analysis results in the base planning conditions starting the first year of the planning horizon in the next IRP; and
l. Include BESS degradation incremental costs.
m. Justify why the L&RB should include the CBM.

Respectfully submitted this 15th day of February 2024.

Chris Burdin
Deputy Attorney General

Technical Staff: Matt Suess
Dylan Moriarty
Jason Talford
Kimberly Loskot
Yao Yin

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15TH DAY OF FEBRUARY 2024, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF TO IDAHO POWER COMPANY,** IN CASE NO. IPC-E-23-23, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

LISA D NORDSTROM
MEGAN GOICOECHEA ALLEN
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: lnordstrom@idahopower.com
mgoicoecheaallen@idahopower.com
dockets@idahopower.com

TIMOTHY E TATUM
ALISON WILLIAMS
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: ttatum@idahopower.com
awilliams@idahopower.com

K. Hawker
SECRETARY