IDAHO POWER.
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June 30, 2022

VIA ELECTRONIC EMAIL

Jan Noriyuki, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-21-43
In the Matter of Idaho Power Company's 2021 Integrated Resource Plan

Dear Ms. Noriyuki:

Attached for electronic filing is Idaho Power Company's Reply Comments in the above-entitled matter. If you have any questions about the attached document, please do not hesitate to contact me.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:cd
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2021 INTEGRATED RESOURCE PLAN	)	CASE NO. IPC-E-21-43
	)	IDAHO POWER COMPANY'S REPLY COMMENTS

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I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Reply Comments to the Idaho Public Utilities Commission ("Commission") in the matter of Idaho Power's 2021 Integrated Resource Plan ("IRP"). These comments respond to Commission Staff ("Staff"), Clean Energy Opportunities for Idaho ("CEO"), Idaho Conservation League ("ICL"), Micron Technology, Inc. ("Micron"), Kiki Tidwell, and the City of Boise.

The 2021 IRP is a comprehensive analysis of the optimal mix of both demand- and supply-side resources needed to reliably serve customer demand and flexible capacity needs over the 20-year planning horizon from 2021 to 2040. Development of the 2021 IRP incorporated meaningful feedback received from Staff and stakeholders during the 2019 IRP review and the public involvement process spanning almost 10 months. For instance, the 2021 IRP includes improvements to scenario modeling and other planning analyses, as well as enhanced process controls. A major improvement in scenario modeling was achieved through leveraging AURORA's refined long-term capacity expansion ("LTCE") model to co-optimize for Idaho Power and the broader west. Additionally, the Company completed significant validation and verification of the modeling, enhanced its reliability analysis, and conducted risk and scenario analyses to ensure the proper selection of the Preferred Portfolio.

The 2021 IRP Preferred Portfolio successfully positions Idaho Power to provide reliable, economic, and environmentally sound service to its customers into the future. The action plan ("Action Plan") associated with the Preferred Portfolio includes the following core resource actions: (1) Conversion of Bridger units 1 and 2 from coal to

natural gas by summer 2024 with a 2034 exit date; (2) Seek to acquire significant capacity and energy resources to meet demand growth needs in 2023 through 2027; (3) Exit from both Bridger Unit 3 and Valmy Unit 2 by year-end 2025; and (4) completing the Boardman-to-Hemingway ("B2H") transmission line by 2026.

Parties to this proceeding generally support the Company's IRP and Action Plan. Idaho Power appreciates Staff's recommendation that the Commission acknowledge the Company's 2021 IRP. The Company's Reply Comments address concerns and recommendations provided by Staff and the other parties.

II. STAFF'S COMMENTS

Staff recommends acknowledgement of Idaho Power's 2021 IRP and recognizes the substantial efforts by the Company to improve its methods and its public process.[1] Staff believes the Company's efforts have improved the credibility of the 2021 IRP. While Staff noted multiple improvements that the Company implemented in the 2021 IRP, Staff also identified concerns it believes need to be addressed in the 2023 IRP. The Company appreciates Staff's thorough review and seeks to address each of the concerns and recommendations herein.

A. Reliability

Idaho Power's 2021 IRP focused on ensuring system reliability. Utilizing the Long-Term Capacity Expansion ("LTCE") capability of the AUORA model, the Company developed resource portfolios under a 50th percentile hourly load forecast and required the AUORA model's LTCE functionality to meet a 15.5 percent peak-hour planning margin for each of the developed portfolios.

[1] Staff's Comments at 3 (Jun. 2, 2022).

Distinct from the approach in the 2019 IRP,[2] the Company's 2021 IRP employed a 15.5 percent target planning reserve margin ("PRM") based on a 1 day in 20 years (1-in-20), or 0.05 days per year, reliability hurdle as determined by a Loss of Load Expectation ("LOLE") analysis. The year 2023 was used as the benchmark year to obtain the PRM value. Idaho Power specifically chose the 1-in-20 reliability threshold to account for two region- and Company-specific considerations that can alter the reliability landscape: 1) extreme weather events that are becoming more frequent, and 2) variability of water availability year to year.[3]

While Staff believes the Company improved how it measures and ensures the reliability of its resource portfolios and how it determines the capacity contribution of current and future resources within its system, Staff has identified two concerns that the Company should address in the 2023 IRP.[4]

1. Reliability Target.

Staff questions the Company's change from a 1-in-10 LOLE target that was used throughout most of the 2021 IRP cycle to the more stringent 1-in-20 target used toward the end of the cycle. Staff believes a reliability target should be determined independent of the Company's load and resources. Instead of using a more stringent target to compensate for the variability of weather, Staff thinks it is more appropriate to incorporate year-to-year variability in both the Company's load forecast and availability of hydro generation in its resource assumptions rather than assuming average weather conditions in the IRP.[5]

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[2] A 15 percent planning margin was used in the 2019 IRP based in part on what peer utilities had selected at the time.
[3] 2021 IRP Appendix C: Technical Report at 99.
[4] Staff's Comments at 6.
[5] *Id.* at 9.

The Company agrees that adjusting the system peak load and hydrogeneration data (instead of the LOLE reliability target) is *another* viable method of accounting for weather variability. For the 2021 IRP, the Company chose to adjust the LOLE reliability target to account for weather variability primarily because it maintains the important historical relationship between load and weather, including the relationship between hydroelectric and variable energy resources.

While a 1-in-10 reliability threshold is used by some utilities, the Company and the Western Interconnection have experienced more frequent extreme weather events in recent years. In addition to the increased frequency of extreme weather events, water availability can significantly alter the resource landscape for Idaho Power and the Pacific Northwest. A poor water year—resulting in reduced hydro generation—can effectively look equivalent to a season-long resource outage. Due to these considerations, the Company chose to align its reliability threshold with that used by the Northwest Power and Conservation Council (NWPCC) of 1-in-20.[6]

2. Ensuring Reliability.

To evaluate the reliability of resource portfolios, the Company utilized four historical test years, and scaled the load in those test years to match the 50th percentile load forecast in future years, thereby allowing the Company to maintain the historical relationship between load and weather (seasonal and daily) when evaluating future years.[7]

As an alternative, the Company considered scaling this load to match a higher percentile load forecast, such as the 70th percentile based on daily peaks or seasonal

[6] https://www.nwcouncil.org/reports/seventh-power-plan/
[7] 2021 IRP Appendix C: Technical Report at 96-99.

energy usage; however, this approach does not account for the variability of weather-dependent resources, such as solar, wind, and hydro (i.e., a poor water year). Rather than attempt to adjust the characteristics and generation profiles of weather-dependent resources, and thereby break the historical relationship in the test years, the Company elected to adjust the reliability target with the expectation of achieving a similar goal of sufficiently modeling resource variability.

Staff concludes that using a more stringent 1-in-20 LOLE target achieves approximately the same result as the Company's prior methodology and does not harm the overall results of the IRP.[8] While the Company believes that its shift to a 1-in-20 reliability threshold is well-supported and justified based on regional considerations, the Company will continue to evaluate and improve its risk-based methods and analyses for the 2023 IRP. The Company will also continue to work with Staff and stakeholders to further refine its reliability-assurance process.

3. Loss of Load Expectation.

Staff offered the Company praise on the new functionality and steps to verify the load-serving assumptions of resources, noting that the Company's approach improves the ability to ensure an accurate measurement for the reliability of its resource portfolios in the 2021 IRP. However, Staff is concerned the Company's method uses only a single year (2023) as a benchmark to calculate the 15.5 percent PRM for all years through the planning horizon.[9] Staff recommends the Company provide justification and additional analysis of other years to confirm the validity of using only a single year in the 2023 IRP.

[8] Staff's Comments at 10.
[9] *Id.* at 6.

The Company appreciates Staff's recognition of the new functionality and the steps taken to ensure an accurate measurement of reliability for the portfolios in the 2021 IRP. While Idaho Power understands Staff's concerns, the Company would like to clarify that the PRM calculation is only the first step in the reliability analysis. The PRM is a good visual representation of reliability and is required as an input into the AURORA model. The AURORA model produces portfolios designed to meet the PRM, but the definitive check of reliability occurs in the LOLE analysis and in meeting the 0.05 days per year LOLE threshold. The Company scrutinized reliability in the years beyond 2023 by identifying LOLEs for each year in every portfolio and ensuring that each year met the 0.05 days per year LOLE threshold. By completing this analysis, the Company verified adequate reliability for all years across the planning horizon, not just 2023.

While Idaho Power is confident in its current approach, Staff's comments and concerns reflect the importance of ongoing discussion and evaluation regarding how to best solve for and implement PRM. The Company will lead such discussions in the 2023 IRP, in which one potential modification might be the replacement of PRM with the Western Power Pool's Resource Adequacy Program, which is currently under development.

B. Load and Resource Balance ("L&R Balance")

Staff concluded that the 2021 IRP L&R Balance was reasonable but recommended that the Company only include market access backed by firm transmission reservations in the L&R Balance.[10] Idaho Power agrees and would like to clarify that the L&R Balance in the 2021 IRP only included firm transmission with a corresponding third-party

[10] *Id.* at 4.

transmission reservation to market hubs. The Company acknowledges that Capacity Benefit Margin ("CBM"), which is also accounted for in the L&R Balance, can only be accessed as firm capacity if Idaho Power is in an energy emergency. Idaho Power will work with Staff and the IRP Advisory Council ("IRPAC") during the 2023 IRP to determine the most appropriate method for including transmission in the L&R Balance.

C. Model Validation and Verification

Staff acknowledged the Company's efforts to improve model validation and verification in the 2021 IRP; however, Staff recommends the Company produce a comprehensive Quality Assurance ("QA") plan in its next IRP that lists all the items the Company verifies or validates in its modeling.[11] The Company appreciates such detailed feedback and hopes for continued constructive analysis that highlights where the process worked well, as well as areas that could be improved upon in the future.

With respect to QA, development of the 2021 IRP involved substantial model checking, validation, and verification tests with a specific focus on validation and verification of items within the Action Plan window. A summary of the model validation and verification tests is provided in Chapter 9: Portfolios - Model Validation and Verification.[12] Staff states that "these tests were key to validating the model results and improved the credibility of the IRP."[13] The Company agrees and believes these QA tests added significant robustness to the modeling process and supported the optimization results and, ultimately, the selection of the Preferred Portfolio.

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[11] *Id.* at 14.
[12] 2021 IRP at 123.
[13] Staff's Comments at 15.

As part of the 2023 IRP, the Company will seek to further bolster and refine its model validation and verification efforts. One change that may prove valuable to Staff and other stakeholders is the addition of a dedicated Model Validation and Verification section of the IRP that would compile information about the various methods used by the Company throughout the IRP process to ensure its validity.

D. Modeling – Development and Evaluation of Portfolios – B2H

Regarding modeling of the Boardman to Hemingway (B2H) transmission line in the 2021 IRP, Staff determined that the Company's development and evaluation of portfolios was appropriate. Staff also concluded that B2H modeling supports the need for the line given planning case input assumptions. However, Staff finds that, based on cost simulations, B2H may be less economical in the presence of high natural gas and carbon prices.[14] Further, Staff disagrees with conclusions the Company drew from a portfolio sensitivity run specifically designed to evaluate B2H, stating:

> . . . these results [of the Base with B2H – High Gas, High Carbon Test sensitivity analysis] are not comparable to any of the results in the table. To make it comparable, the Company would need to generate portfolios for all Base scenarios using the high gas and carbon price inputs and then simulate them through the production cost model using the same planning gas and carbon prices to compare against the $7,997,339 amount and high gas and high carbon prices to compare against the $9,424,935 amount. Until the Company runs this analysis, Staff believes that increasing gas prices and legislating carbon restrictions may make B2H less economical.[15]

Idaho Power notes that B2H sensitivity analyses were conducted in several ways to contemplate the economics of the project under various conditions and assumptions.

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[14] *Id.* at 16.
[15] *Id.*

Staff's suggestion would require extensive effort to perform additional LTCE analyses, including developing a re-optimized resource portfolio for the Western Electricity Coordinating Council (WECC). Additionally, portfolios with and without B2H would have to be developed and compared. As a reasonable alternative, the Company instead focused on a range of well-designed validation and risk assessments (i.e., sensitivities, scenario analysis, and stochastic risk analysis) to ensure that the 2021 IRP Preferred Portfolio is the most economical choice over a broad range of alternative future scenarios.

The Test scenario shared in Table 10.3 of the 2021 IRP, and referenced by Staff, was developed to test B2H as an independent variable, assuming the renewable resource mix was the same between the Base with B2H and Base without B2H portfolios. The resource makeup of the Base with B2H, Base without B2H, and Base with B2H – High Gas, High Carbon Test portfolios are shown in the table below:

Table 1: Planning Condition Optimized Resource Additions

Resource	Base with B2H (MW)	Base without B2H (MW)	Base with B2H – High Gas, High Carbon Test
Wind	700	1,300	1,300
Solar	1,405	1,805	1,805
Storage	1,685	2,115	1,570
B2H	WITH	WITHOUT	WITH

In these portfolios, the inclusion of B2H is a key differentiator, and the project's absence drives changes in portfolios. The Base without B2H portfolio (under planning conditions) required 1,430 megawatts ("MW") of **additional** resources (600 MW of additional wind, 400 MW of additional solar, and 430 MW of additional storage) to perform the same functions as the Base with B2H portfolio.

In the analysis,[16] wind and solar prices are fixed following construction and are unaffected by increases in gas and carbon prices. Therefore, the larger quantities of wind and solar in the Base without B2H portfolio are precisely why that portfolio performed well in a high-gas and high-carbon price future -- not the lack of B2H. The Company also tested whether B2H would remain a preferred resource in a high-gas and high-carbon price future if in a portfolio assigned the same resource mix as the Base without B2H portfolio. This new portfolio was named "Base with B2H – High Gas High Carbon Test" and the wind and solar additions mirrored those of the Base without B2H portfolio, as shown above in Table 1. Confirming Idaho Power's assumptions about the function and value of B2H in a portfolio, the Base with B2H – High Gas High Carbon Test portfolio had superior cost performance compared to the Base without B2H portfolio in a high-gas and high-carbon price future.

In addition to this single test scenario, the Company performed a robust analysis of various portfolios through scenario and stochastic risk analyses. The stochastic risk analysis showed that across a range of hydro conditions, customer loads, and natural gas prices, the Base with B2H portfolio was the best combination of least cost and least risk.[17] Based on the comprehensive stress testing of B2H and other scenario analyses, the Company is confident that the Base with B2H portfolio is the best option for minimizing both cost and risk and, as a result, is the appropriate choice for the Preferred Portfolio.[18]

In the 2023 IRP, the Company plans to further develop and expand its approach to stochastic analysis, including advanced modeling of carbon price volatility to better

[16] 2021 IRP at 130.
[17] 2021 IRP Appendix C: Technical Report at 92-95.
[18] 2021 IRP at 131.

elucidate the costs and risks of each portfolio. These methods may replace the scenario analysis performed in the 2021 IRP.

E. Modeling – Evaluation and Mitigation of Risk

1. B2H Risk.

Staff is concerned by the extent to which the Company is relying on B2H to meet future capacity needs. Staff believes that a cost overrun of 30 percent or a slip in schedule of one year is may be realistic given current rates of inflation and supply chain issues that may persist into the future. Staff also notes that transmission siting issues have historically been difficult for Idaho Power to resolve.[19]

The Company performed robustness tests related to depth of the Mid-C market, project cost, and timing of the project.[20]

To test market depth, the Company evaluated varying levels of B2H capacity. Holding total project costs constant, the Company assessed the change in portfolios costs assuming the Company could only access 350 MW, 400 MW, 450 MW, 500 (the Preferred Portfolio), and 550 MW of resource-equivalent capacity. In the most conservative 350 MW scenario, the effective cost of B2H increased by 43 percent on a dollar-per-MW basis. In these tests, simply reducing available B2H capacity was not sufficient, as any reduction in capacity would need to be offset by equivalent resource additions to ensure sufficient resources to meet forecasted load. Therefore, the Company replaced the determined shortfall of B2H capacity in each test portfolio with the equivalent amount of battery storage. In doing so, the Base B2H Portfolio with B2H assigned 350 MW resource-equivalent capacity was still $139 million less than the Base without B2H PAC Bridger

[19] Staff's Comments at 17.
[20] 2021 IRP at 144-146.

Alignment portfolio (the least-cost non-B2H portfolio).[21] Because the B2H project will continue to have 500 MW of capacity, even if only 350 MW is utilized by the Company to meet its customers' peak needs, the Company could sell the 150 MW differential to a third-party to offset customer costs. In this case, the portfolio with B2H is $190 million less than the least-cost non-B2H portfolio.

For comparison purposes, the difference between the Preferred Portfolio (B2H assigned 500 MW of resource-equivalent capacity) and the least-cost non-B2H portfolio is $266 million.[22] Therefore, even a substantial reduction in the Company's ability to import power with B2H still results in B2H remaining a vital and cost-effective part of the Preferred Portfolio. Importantly, through the B2H arrangement, Idaho Power will also gain 200 MW of bidirectional capacity to the Four Corners market hub in northwest New Mexico. The Company did not incorporate the benefits of this additional access, even though it brings meaningful diversity benefits (i.e., transacting at a different market hub) and may provide summer capacity.

While B2H is one of the higher-cost resources, it also provides 500 MW of summer capacity, making it the least-cost resource on a cost per MW basis.[23] In the 2021 IRP, Idaho Power assigned B2H a zero percent cost contingency in the Preferred Portfolio to maintain consistency with other resources that are modeled with zero cost contingency. As part of the B2H cost risk evaluation in this IRP, the Company evaluated B2H with a 0, 10, 20, and 30 percent cost contingency. Under the 30 percent cost contingency scenario, the net present value ("NPV") of B2H applicable to the 2021 IRP planning horizon

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[21] *Id.* at 145.
[22] *Id.*
[23] 2021 IRP Appendix D, Table 5, at 34.

increases $56.5 million from the Preferred Portfolio.[24] Given the $266 million gap between the Preferred Portfolio, and the lowest-cost non-B2H portfolio, a $56.5 million cost increase (as found in the 30 percent cost continency analysis) would not alter selection of the Preferred Portfolio. This evaluation further shows that B2H can absorb significant cost risk, even above the 30 percent evaluated, and still be cost-effective.

Importantly, the IRP analysis only evaluated cost risk associated with B2H. The Company did not stress test other resource types, even though their costs and construction timelines have the same potential (if not more) to be impacted by current economic conditions (i.e., inflation) and supply chain issues. Supply chain and inflation issues are currently causing schedule delays and cost impacts on many types of energy resources, including energy storage, solar, wind, and natural gas facilities. Any apples-to-apples comparison would need to include equivalent contingency assumptions for other resources.

Lastly, the Company evaluated the impact of a one-year delay in the B2H in-service date from 2026 to 2027 and developed a re-optimized portfolio to evaluate that risk. This one-year delay reduced the $266 million difference between the Preferred Portfolio and least-cost non-B2H portfolio to $196 million.[25] As the project in-service date draws closer, more will become known and certain. In this regard, the Company received positive news on the B2H permitting front at the end of May 2022. The Administrative Law Judge, who oversees the Company's permit application through the Oregon Department of Energy's Energy Facility Siting Commission ("EFSC") process, recommended EFSC

[24] 2021 IRP at 145.
[25] *Id.* at 146.

approve the Company's B2H permit and issue a Final Order and site certificate.[26] The Company is hopeful B2H construction can begin next year.

2. Flexible Resource Strategy.

Staff also expressed concern related to the lack of risk mitigation and flexibility strategies included in the Company's IRP and recommends that the Company study the costs and benefits of implementing a flexible resource strategy in the 2023 IRP.[27] The Company appreciates Staff's concern around developing a strategy of resource flexibility that could proactively mitigate a rapidly changing energy environment. The Company understands this concern and believes the 2021 IRP addressed much of that flexibility and uncertainty in the following ways:

- *Resource Diversity* – Expanded transmission will provide renewable resource diversity (solar and wind across the Western Interconnection), as well as load diversity. The Company will continue to look at other resource options in the 2023 IRP.
- *Market Hub Access* – B2H will provide additional access to the Mid-C market, as will the PacifiCorp asset swap associated with B2H. The Company will also gain 200 MW of bidirectional ownership capacity to the Four Corners market hub in northwest New Mexico. The SWIP North portfolio sensitivity also suggested that project may be beneficial to explore as well.

[26] *In the Matter of the Application for Site Certificate for the Boardman to Hemingway Transmission Line*, OAH Case No. 2019-ABC-02833, Proposed Contested Case Order at 296 (May 31, 2022).
[27] Staff's Comments at 6 and 27.

- *Scalable/Modular Resources* – the Company identified small battery storage projects that could be placed at substations to defer planned transmission and distribution upgrades. The Company will continue to look for these opportunities.

Additionally, the Company's Preferred Portfolio achieves resource diversity through acquisition of large amounts of wind and solar resources, as well as 1,685 MW of battery storage, which will serve as a flexible resource that can aid in serving peak load and also absorb power during times of excess renewables relative to load.

As for the 2023 IRP, the Company will continue to analyze the potential of small modular nuclear, as well as hydrogen and other future fuel types, as resources in the IRP. The Company looks forward to future engagement with Staff in developing and implementing a more robust flexible resource strategy in the next IRP.

F. Supply-Side Resources

The Company appreciates Staff's review of the various supply-side resources included in the 2021 IRP and will in turn address the areas of concern identified by Staff.

1. Coal Unit Exits.

Staff believes timing of coal unit exits and replacement with new resources significantly impact customer rates and without proper planning may impact system reliability. Because of this, Staff thinks the negotiation of an exit agreement should have been included in the Company's 2021 IRP action plan and recommends that it be incorporated into its coal plant exit costs to properly value different exit dates in the Company's portfolios in the 2023 IRP.[28]

[28] *Id.* at 21-22.

During the 2021 IRP process, the Company incorporated the most current information into the coal exit date assumptions. Due to the uncertainty of exit dates at Bridger, the Company included an Action Plan item to "Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028." The Company recognizes that the negotiation of exit agreement(s) is critical for the 2023 IRP and is working with PacifiCorp, as well as necessary stakeholders, and more details will be shared as available in the 2023 IRP.

2. Renewable Energy and Storage Resources.

Staff is concerned by the Company's transition toward Variable Energy Resources ("VERs") and energy storage in the 2021 IRP compared to the 2019 IRP. While Staff recognizes the benefit of zero-fuel cost VERs, as the Company works toward its clean energy goal, Staff reminds the Company that it is obligated to continually assess system reliability and its need to maintain adequate dispatchable resources whether by deferring its planned exits from coal units or its natural gas generating resources.[29] Idaho Power agrees that the 2021 IRP shows a markedly different Preferred Portfolio compared to the 2019 IRP. A key factor for the shift toward significantly more VERs and storage was the decrease in cost assumptions for new VERs and storage between the two IRPs.

Given the significant change between IRPs, the Company compared the results of the 2021 IRP Preferred Portfolio buildout to the resource mix from the NWPCC WECC buildout in their 2021 Power Plan.[30] The two plans show a similar mix of resources in their regional projections. Additionally, to ensure the shift towards VERs and energy storage

[29] *Id.* at 22.
[30] 2021 Northwest Power Plan at 51, https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

could occur while maintaining system reliability, Idaho Power performed a LOLE reliability analysis for each portfolio to ensure they maintained adequate system reliability.[31]

Ultimately, Idaho Power agrees with Staff that a continued focus on assessing system reliability and maintaining adequate dispatchable resources is important, especially as it pertains to carbon emitting resource exits, and the Company will continue to monitor this in the 2023 IRP.

3. Natural Gas Conversion.

Staff states there is a level of uncertainty regarding the Company and PacifiCorp's implementation of the planned conversion. Uncertainties include federal and state regulations, date of conversion, future operating cost, and costs for eventual decommissioning and retirement.[32] While the Company understands Staff's concerns around these uncertainties, the cost, timeline and permitting information the Company used in the 2021 IRP was informed by PacifiCorp's recent conversion of Naughton Unit 3 from coal to natural gas. Idaho Power will keep Staff apprised of the conversion process as more information is known and will include updated information in the 2023 IRP.

4. Natural Gas Forecast.

Staff believes the Company's analysis and utilization of the Energy Information Administration ("EIA"), New York Mercantile Exchange ("NYMEX"), and Moody's data to verify that Platts' forecast is appropriate for planning purposes and the use of the forecast in the IRP is reasonable.[33] Idaho Power agrees with Staff's assessment of natural gas prices and using

[31] 2021 IRP Appendix C: Technical Report at 96-100.
[32] Staff's Comments at 23.
[33] *Id.* at 19.

Platts' natural gas price forecast for planning purposes. Given current natural gas price volatility, the Company concurs with Staff's recommendation to monitor natural gas price forecasts and market conditions and will share insights with the IRPAC during the 2023 IRP cycle.

G. Demand-Side Resources

1. Energy Efficiency.

Staff believes the addition of EE bundles is an improvement to the IRP and encourages the Company to continue refining this method of allowing additional EE selections in the IRP to help alleviate energy constraints throughout the IRP planning horizon.[34] The Company appreciates Staff's feedback and agrees that the recent additions of EE bundles in the 2019 and 2021 IRPs were an improvement over prior iterations of the IRP. The Company commits to evaluate the method used in the 2021 IRP for subsequent reports.

2. Demand Response.

Reviewing DR in the 2021 IRP, Staff recognizes that a threshold cap is likely necessary to implement for additional DR capacity due to ramping issues with new DR programs. Therefore, Staff recommends the Company discuss and explore adjusting the 20 MW threshold cap on additional DR capacity in the 2023 IRP.[35] Idaho Power agrees and will discuss and explore adjusting the threshold cap on additional DR capacity with its Energy Efficiency Advisory Group ("EEAG") and the IRPAC in the development of the 2023 IRP. Idaho Power will continue to monitor existing DR program participation and adjust its estimates for available DR capacity for use in the 2023 IRP.

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[34] *Id.* at 24.
[35] *Id.* at 25.

H. Action Plan

Staff's concluding remarks on the Company's 2021 IRP are focused on the Action Plan and state that because the Commission only acknowledges the IRP, Staff believes that most of the resources included in its IRP portfolios should be considered as proxies.[36] However, Staff noted certain exceptions to this process citing transmission resources included in the Company's Preferred Portfolio that do not fit within the definition of a proxy resource."[37] Finally, when it comes to resource acquisition Staff posits that a sufficient set of alternative resources is required to allow for competitive bidding in the Company's request for proposals ("RFP") to obtain a reasonable low-cost resource.[38]

The Company is in alignment with Staff's comments on this topic. The Company views the IRP Action Plan as an indicative plan but not a prescriptive one. The Preferred Portfolio selects a mix of 700 MW of new generic Idaho and Wyoming wind resources in 2024,[39] however, the accompanying Action Plan item is more generic: "Issue an RFP to procure resources to meet identified deficits in 2024 and 2025." When the Company goes to acquire the new resources, it will engage in an all-resource RFP and the results of that RFP may be dramatically different than the 700 MW of wind identified in the IRP modeling. The resources selected through the RFP process are those that can meet the identified energy and/or capacity needs on a least-cost and least-risk basis. In this way, the Company has not called the new resources in the IRP proxies but has treated them as such. The exception to this generic process, as noted by Staff, is for specific decisions

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[36] *Id.* at 25-26.
[37] *Id.* at 26.
[38] *Id.*
[39] 2021 IRP at 4, Table 1.1.

like the retirement or exit of existing resources and changes to transmission system topology.

III. CEO COMMENTS

CEO notes that as an active participant in the development of several of the recent IRP documents, they congratulate the Company on the improvements recently introduced, yet are concerned about remaining limitations in the software and analytical processes employed to produce the IRP plans. CEO respectfully suggest Idaho Power consider two areas for careful review before developing the 2023 IRP.

A. Energy Storage Modeling

CEO suggests that the Company improve the ability of the software used (whether AUORA or some other product) to analyze effects of battery storage on diurnal market price patterns. This recommendation comes after a review of the Mid-C hourly prices used when analyzing the Preferred Portfolio in the 2021 IRP.[40] The primary concern being that given a battery's ability to arbitrage, the daily price spreads seem unrealistically high.[41] Finally, CEO conjectures that the modeled daily price spread may materially overvalue portfolios with enhanced access to Mid-C.

CEO's arguments for lowered daily price spreads resulting from increased energy arbitrage due to battery storage are unsupported and counter to the data presented in the IRP. For an actionable arbitrage opportunity to exist, the price spread must be greater than the cost to utilize it. That is, a rational investor would not attempt energy price arbitrage if they could not cover the expenses and receive a return on investment. Using the LCOE data in the year 2021 for a 4-hour Li-battery, a rational investor would not be

[40] CEO's Comments at 2 (Jun. 2, 2022).
[41] *Id.* at 3, the Mid-C price forecasts evaluated were 2023 and 2033.

able to create a profitable arbitrage opportunity if price spreads were less than $130/MWh.[42] Applying the cost curves found in Appendix C[43], the minimum profitable arbitrage price in 2023 would reduce to $115.44/MWh and in 2033 is $81.61/MWh. Far from being "unrealistically high," the daily price spreads from the IRP modeling are well below the minimum profitable arbitrage prices for battery storage. Merits of CEO's arguments notwithstanding, the Company will continue to evaluate how storage is used in its planning models in subsequent IRPs as storage technologies develop and model capabilities expand. In the 2021 IRP model, storage resources were built as a capacity resource whose primary objective was to reduce peak demand net of must-run resources and provide firming and ancillary services for the integration of renewables.

Lastly, CEO concludes that portfolios (such as those with the B2H transmission line) with enhanced access to Mid-C markets may have been materially overvalued in the 2021 IRP analyses. This conclusion is unsupported conjecture and is counter to the data. The IRP modeling shows that the next least cost portfolio without B2H under planning conditions is $266 million more expensive on a net present value basis than the Preferred Portfolio with B2H.[44]

B. Discount Rate

CEO believes the Company is using an inappropriately high discount rate which inherently introduces bias into its associated cost analysis process, inherently understating the cost exposure in portfolios which are more exposed to those types of costs (such as carbon emission charges) that rise dramatically over the 20-year forecast

[42] 2021 IRP at 111.
[43] 2021 IRP Appendix C: Technical Report at 44-45.
[44] 2021 IRP at 8.

period.[45] CEO strongly believes that the appropriate base for converting future year cost estimates back to a present value requires using a discount rate that reflects the customer's cost of short-term funding.[46]

Idaho Power disagrees with CEO and believes using its authorized after-tax weighted average cost of capital ("WACC") to discount the cost of modeled portfolios is appropriate because this rate best represents the overall long-term cost of capital to the Company in financing its operations.

Under Idaho's regulatory mandate and model, the Company has an obligation to provide adequate, efficient, just, and reasonable service on a nondiscriminatory basis to all those that request it within its certificated service area.[47] In return, Idaho Power has an opportunity to earn a reasonable return by investing capital into the resources and systems necessary to perform its service obligation.[48]

The use of Idaho Power's after-tax WACC is consistent with prior years' IRPs, serving as a clear and understandable method for measuring future customer obligations, much of these driven by capital costs within the comparable portfolios, at a present value. When comparing forecast costs of different portfolios, it is vital that the same discount rate be used to have an 'apples to apples' comparison of each portfolio's cost at a present value.

Finally, Idaho Power wishes to address CEO's closing comment, in which CEO states:

> However, when the bias in favor of B2H arising from what CEO sees as unrealistic arbitrage opportunities in the hourly

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[45] CEO's Comments at 4.
[46] *Id.* at 5.
[47] *Idaho Code* §§ 61-302, -315, and -507.
[48] *Application of Citizens Utilities Co.*, 112 Idaho 1061, 1067, 739 P.2d 360, 366 (1987).

> Mid-C market price forecast is combined with an up to $¾ billion understatement of carbon emission cost exposure associated with the B2H portfolio due to the use of an inappropriately high discount rate, we see opportunities for improvement in future IRP analyses.[49]

First, it is important to note that resource portfolios are optimized based on the inputs provided by the Company. All inputs to the model were developed using the Company's WACC as the discount rate. To take the final cost results of a portfolio optimized based on the Company's WACC and apply a different discount rate to the final outputs than was applied to the inputs is inappropriate. If utilizing a lower discount rate for model inputs, the Company's LTCE model would have developed different portfolios and a different set of portfolio costs. Simply put, one can't take the portfolios developed in the 2021 IRP utilizing the Company's WACC, and then apply a different discount rate to the portfolio cost stream and draw any meaningful conclusion.

IV. ICL COMMENTS

ICL recognizes that the 2021 IRP represents an incremental improvement over the 2019 IRP. Pointing out improvements, ICL cites improved assessment of Bridger coal exit dates, improved assessment of clean energy options and improved modeling of demand-side resource potential. However, ICL believes there are four shortcomings in the planning process that the Commission should direct Idaho Power to address in the future. The four issues cited by ICL are discussed in the Company's reply in the following sections.

[49] CEO's Comments at 6.

A. Bridger Conversion

ICL argues that the Bridger Units 1 and 2 natural gas conversion was late in the process and used speculative inputs.[50] The Company agrees that the natural gas conversion was introduced later in the cycle of the 2021 IRP—this is because the information was brought to the Company late in the IRP process. However, Idaho Power strongly disagrees with the assessment that this limited stakeholder's ability to collaborate with the Company. At the first opportunity after learning of PacifiCorp's intention to pursue a conversion of Units 1 and 2 at Bridger, the Company presented the details to the IRPAC members in October 2021 and solicited comments and feedback.[51]

Additionally, ICL's claim of the speculative nature of the modeling inputs to assess the conversion is baseless. The inputs were informed by actual coal-to-natural gas conversions. Idaho Power's Bridger plant partner, PacifiCorp, recently converted Naughton Unit 3 to natural gas and is familiar with the costs and process.[52] The details for the conversion related to timeline, permitting, and cost were provided to the Company by PacifiCorp based on their experiences at Naughton. Again, these details were discussed with IRPAC members in the October 21, 2021 meeting.[53]

B. Natural Gas Price Forecast

ICL believes that the planning case natural gas price forecast is wrong, and the method of analysis prevents rigorous evaluation.[54] The Company disagrees with many of the erroneous comments made by ICL in relation to the natural gas price forecast. ICL

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[50] ICL's Comments at 4 (Jun. 2, 2022).
[51] 2021 IRP Appendix C: Technical Report at 4.
[52] PacifiCorp 2021 IRP table 10.2 at 327.
[53] Bridger Units 1 & 2 Natural Gas Conversion IRPAC Presentation (Oct. 21, 2021). https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/Bridger%20Natural%20Gas%20Conversion.pdf
[54] ICL's Comments at 6.

stated numerous times that the forecast used for the 2021 IRP was either "highly confidential" or "secret"[55] when the record and process show the opposite. The natural gas price forecast methodology was presented by the forecast vendor directly to the IRPAC on March 11, 2021, and a follow up discussion was held on June 10, 2021.[56] Further, an abridged version of the forecast methodology and drivers was provided in the 2021 IRP.[57]

As to the accuracy of the Platt's forecast, the Company used the natural gas price forecast after performing an evaluation of available forecasts. Based on the available information and thorough examination of the available forecasts at the time the IRP analysis was done, the gas forecast used was determined to be most appropriate.[58] The assessment of the natural gas price forecast accuracy provided by ICL suffers acutely from hindsight-bias. None of the natural gas forecasts available before the filing of the 2021 IRP showed a significant change in gas markets as a result of the Russian invasion of Ukraine.

Lastly, ICL's claim that "Despite clear and broad-based skepticism by the IRP Advisory Committee, Idaho Power chose to use a highly confidential gas price forecast methodology purchased from Platts,"[59] is also unsupported. The Company noted a lively discussion of the gas forecast during the March 11, 2021 meeting, but during the follow up conversation on June 10, 2021, the only observed skepticism came from ICL. Notwithstanding, the Company continues to monitor inputs to the IRP and will evaluate

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[55] *Id.* at 6, 7 and 11.
[56] 2021 IRP Appendix C: Technical Appendix at 3,
[57] 2021 IRP at 103-106,
[58] *Id.* at 105.
[59] ICL's Comments at 6.

natural gas price forecasts and market conditions and will share insights with the IRPAC during the 2023 IRP cycle.

C. Customer-Owned Solar

ICL claims Idaho Power's "2021 IRP neglects to model the resource capacity of customer-owned solar and storage resources"[60] The Company disagrees with ICL's assessment. Customer-owned generation was accounted for within the load forecast, resulting in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2040, the annual residential sales forecast reduction was about 65 aMW, the commercial reduction was 3 aMW, and the irrigation reduction was 6 aMW.[61]

ICL has asked the Company to develop policies including a value of solar ("VOS") that is stable over the long term that will support solar investments, as well as develop a customer-owned community solar program (virtual net metering).[62] While these recommendations are outside the scope of the IRP, Idaho Power supports its customers' pursuit of clean energy and is currently working with Staff and stakeholders on a VOS (the Value of Distributed Energy Resources—or VODER—study) through the on-site generation docket in Case No. IPC-E-22-22.[63] The Company has also committed to include the community solar issue in a future Clean Energy Your Way ("CEYW") stakeholder workshop.[64]

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[60] *Id.* at 8.
[61] 2021 IRP Appendix A: Sales and Load Forecast at 35.
[62] ICL's Comments at 9.
[63] *In the Matter of Idaho Power Company's Application to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefits of On-Site Customer Generation & for Authority to Implement Changes to Schedules 6, 8, and 84 for Non-Legacy Systems,* Case No. IPC-E-22-22.
[64] *In the Matter of Idaho Power Company's Application to Expand Optional Customer Clean Energy Offerings Through the Clean Energy Your Way Program,* Idaho Power Reply Comments at 21-22 (Jun. 2, 2022).

D. Policy Driven Scenarios

ICL stated their appreciation for Idaho Power's collaboration to assess four future scenarios that help inform the Company, stakeholders, and this Commission about attributes and costs for the energy system of the future and recommends the Commission encourage Idaho Power to continue to model this type of policy-driven futures along with the traditional assessment.[65] Idaho Power appreciates ICL's positive response to the rapid electrification, climate change, Clean by 2035, and Clean by 2045 scenario analyses in the 2021 IRP. The Company will continue to model various types of policy-driven futures along with the traditional assessment of differing assumptions about loads, gas prices, and hydro generation in the 2023 IRP.

V. MICRON COMMENTS

As Idaho Power's largest customer, Micron is keenly interested in all aspects of Idaho Power's cost of service and service reliability, including Idaho Power's resource planning processes and the types of resources used to serve its electric load.[66] The Company appreciates Micron's participation in the planning process and their support in its transition to clean energy. Micron also notes that the Company supports customers' clean energy needs and, as such, recommends that the Commission ensure Idaho Power plans future resource procurements with an eye toward other large loads that may transition to customer specific resources to ensure it does not procure excess resources.[67] While the Company cannot always predict if a future resource may be a good

[65] ICL's Comments at 9-10.
[66] Micron's Comments at 1 (Jun. 2, 2022).
[67] *Id.* at 2.

candidate for a large load customer's clean energy objective, the Company commits to evaluating resource needs wholistically to ensure it doesn't procure excess resources.

While Micron supports Idaho Power's clean energy transition, they encourage Idaho Power to continually investigate and implement strategies to mitigate the rate impacts of the transition. Idaho Power is sensitive to the rates and charges paid by its customers. Through the IRP process, the Company seeks to produce a portfolio of resources that represents the least-cost, least-risk path to serving its customers' needs over the planning horizon.

VI. KIKI TIDWELL COMMENTS

A. Generation Capacity Concerns

In her comments, Ms. Tidwell describes the near-term generation capacity shortfalls and the various challenges that Idaho Power may face, including market access issues, the delay of Jackpot Solar, relicensing of various hydroelectric facilities, a delay in the construction of B2H, and the risks of losing generation capacity at Jim Bridger Units 1 and 2 due to environmental compliance obligations.[68]

The Company acknowledges the importance of reasonable resource assumptions to ensure Idaho Power can reliably serve the needs of its customers. Significant adjustments were made in the 2021 IRP to reflect the changing planning environment. These changes include adjustments to the assumptions for market purchases in the L&R Balance and updated capacity contributions for thermal and DR resources.

Regarding relicensing efforts associated with hydro facilities, the Company believes that relicensing will occur and that these facilities will continue to provide low-

[68] Kiki Tidwell's Comments at 2-5 (Mar. 21, 2022).

cost capacity to Idaho Power and its customers. As stated earlier in response to Staff's comments, the Company anticipates receiving a B2H permit in 2022 and acknowledged construction delays were possible. To test the impact of a delay, the Company evaluated a 2027 in-service date as a sensitivity in the 2021 IRP, as described above in response to Staff's comments.[69] The Company plans to work with its partner PacifiCorp in the conversion of Jim Bridger Units 1 and 2 to natural gas over the next few years, which will allow the Company to retain needed dispatchable capacity while also reducing emissions relative to coal-fired resources.

B. Climate Change and Emissions

Ms. Tidwell noted that she is affected by climate change and that the carbon emissions from Idaho Power's operations are contributing to climate change.[70] The Company believes Ms. Tidwell's concerns are addressed in the new Climate Change chapter of the IRP Report, which focused on identifying climate-related risks, discussing the Company's approach to monitoring and mitigating identified risks, and examining climate-related risk considerations in the IRP.[71] The Company also included a climate-related risk assessment in the 2021 IRP. Specifically, the Company conducted additional scenarios to explore the impact these events could have on Idaho Power's system. These scenarios are detailed in Chapter 9 of the 2021 IRP.

Ms. Tidwell also points out that the Preferred Portfolio greenhouse gas emissions are higher than the Clean by 2045 scenario run in the 2021 IRP. While this is true, the "100% Clean By" scenarios were significantly more expensive than the Preferred

[69] 2021 IRP at 125.
[70] Kiki Tidwell's Comments at 5.
[71] 2021 IRP at 27-34.

Portfolio. The Company is confident that the selected Preferred Portfolio is the best combination of least cost and least risk. Further, the path to Idaho Power's 2045 clean energy goal will not be perfectly linear—and, as such, the emissions reduction path will not be perfectly linear. The Company will have to adjust and adapt as new technologies and opportunities become available and cost-effective.

It should not go unnoticed, though, that the 2021 IRP represents a significant departure from the 2019 IRP with respect to clean resources in the Preferred Portfolio: 700 MW of wind, 1,405 MW of solar, 1,685 of battery storage, 100 MW of demand response, 440 MW of energy efficiency, and 500 MW of transmission. Idaho Power believes it is planning appropriately and making strides toward its 2045 goal.

VII. CITY OF BOISE COMMENTS

Idaho Power appreciates the City of Boise for their participation in the 2021 IRP planning process and for their support of the Company's plan. Specifically, the City of Boise recommends the Commission acknowledge the 2021 IRP.[72] The Company is eager to convene the IRPAC in September to assist in development of the 2023 IRP and looks forward to continued work and collaboration with the City of Boise.

VIII. CONCLUSION

Based on the detailed and comprehensive analysis set forth in the IRP, Idaho Power has demonstrated that its preferred portfolio, which includes the B2H transmission line as a least-cost, least-risk resource, meets the resource need identified in this IRP. Idaho Power respectfully requests the Commission accept and/or acknowledge the

[72] City of Boise's Comments at 1 (submitted June 2, 2022).

Company's 2021 IRP as meeting both the procedural and substantive requirements of Order Nos. 22299, 25260, and 30317.

DATED at Boise, Idaho, this 30th day of June 2022.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 30th day of June 2022, I served a true and correct copy of Idaho Power Company's Reply Comments upon the following named parties by the method indicated below, and addressed to the following:

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