DAYN HARDIE
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0312
IDAHO BAR NO. 9917

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

Attorney for the Commission Staff

RECEIVED
2022 JUN -2 PM 5:25
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

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

BACKGROUND

The Integrated Resource Plan ("IRP") is Idaho Power's (the "Company") status report explaining how the Company plans to adequately and reliably serve customers over the next 20 years. The Commission requires the Company to file an IRP every two years, and to allow the public to participate and comment as the IRP is being developed. *See* Order Nos. 22299 and 25260.

On December 30, 2021, the Company filed its 2021 IRP requesting Commission acknowledgement. By acknowledging the IRP, the Commission is acknowledging the Company's ongoing planning process, not the conclusions or results reached through that process. Order No. 33441.

Further, the Commission has stated it

> does not approve the IRP or any resource acquisitions referenced in it, endorse any particular element in it, opine on Idaho Power's prudence in selecting the IRP's preferred resource portfolio, or allow or approve any form of cost recovery. The appropriate place to determine the prudency of the IRP or Idaho Power's decision to follow or not follow it, and the validation of predicted performance under the IRP, is a general rate case or other proceeding where the issue is noticed.

Order No. 34959.

The Commission required that a utility's IRP explain its current load/resource position, its expected responses to possible future events, and the role of conservation in its explanations and expectations. The IRP should also discuss:

> any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand- and supply-side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

Order No. 22299.

The IRP should separately address:

- "Existing resource stack" by identifying all existing power supply resources;
- "Load forecast" by discussing expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. This section should be a short synopsis of the utility's present load condition, expectations, and level of confidence; and
- "Additional resource menu" by describing the utility's plan for meeting all potential jurisdictional load over the 20-year planning period, with references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

Id.

The Company's primary goals of its "2021 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period (2022-2041); (2) ensure the selected resource portfolio ("preferred portfolio") balances cost and risk, while including environmental considerations; (3) give balanced treatment to both supply-side resources and demand-side measures; and (4) involve the public in the planning process in a meaningful way." Application at 3.

Based on the Company's preferred portfolio, the IRP contains a short-term action plan that would: (1) add 120 megawatts ("MW") of solar photovoltaic ("PV") capacity in 2022; (2) convert Jim Bridger units 1 and 2 to natural gas by summer 2024; (3) seek acquisition of significant resources to meet energy and capacity needs in 2023 through 2027; (4) exit Jim Bridger unit 3 and Valmy unit 2 by year-end 2025; and (5) energize Boardman to Hemingway ("B2H") in 2026.

STAFF REVIEW

Staff recommends acknowledgment of the Company's 2021 IRP while recognizing substantial efforts by the Company to improve its methods and how it conducted its public engagement process. Compared to the Second Amended 2019 IRP ("2019 IRP"), Staff believes the Company's efforts have improved the credibility of the 2021 IRP results.

Staff is encouraged by the progress the Company has made in evaluating its own process and the number of improvements implemented in the 2021 IRP. Key improvements implemented in the 2021 IRP include:

1. Implementation of a reliability model integrated with the Company's overall IRP methodology that builds portfolios based on a Loss of Load Expectation ("LOLE") target and provides closed-loop verification that portfolios meet the target over the 20-year planning horizon;
2. Determination of the peak-serving capability or Effective Load Carrying Capability ("ELCC") of renewable and time-limited resources using probabilistic best practice processes and based on historical output data;
3. The ability of the Long-Term Capacity Expansion ("LTCE") software to cost optimize the mix of resources within the Company's system;
4. Methods to verify that the Company's models operated as expected and validated that the model produced cost optimized portfolios for the Company's system; and
5. Modifications to the Company's Demand Response ("DR") programs as a result of its reliability evaluation processes and identification of the hours when capacity needs are the greatest.

In addition to improvements that the Company implemented in the 2021 IRP, Staff identified additional concerns it believes need to be addressed in the 2023 IRP (Items 1-7) and in its current action plan (Items 6 and 7). Staff recommends:

1. Incorporating acceleration of extreme weather events and variability of water availability through its load and resource input assumptions, rather than compensating by changing the LOLE reliability target;
2. Only including market access backed by firm transmission reservations in the Load and Resource Balance ("L&R");
3. Evaluating the risks and inaccuracies from employing a single benchmark year (2023) to determine the LOLE-based Planning Reserve Margin ("PRM");
4. Providing a comprehensive Quality Assurance ("QA") plan to verify and validate its models by describing the purpose of each test, how the test was conducted, and the result;
5. Including a study of the costs and benefits of implementing a flexible resource strategy;
6. Developing a Bridger exit agreement with PacifiCorp that determines potential costs of extending or exiting operations early like the exit agreement developed for the closure of Valmy and incorporate those costs into its coal plant exit costs to properly value different exit dates in the Company's portfolios;
7. Not including acquisition of specific types of resources in its action plan where a broadly-scoped RFP is appropriate.

The improvements in this IRP have sharpened focus on the shortcomings in the 2019 IRP and the impacts it is having on the Company's immediate need for resource procurements and the need to find ways to acquire resources inside of resource acquisition lead time. Evidence of these shortcoming include:

1. Shifting the first capacity deficit date from 2029 as reflected in the 2019 IRP to 2023 in the 2021 IRP, with even earlier deficits occurring in 2021 and 2022 that cannot be addressed due to resource acquisition lead times;
2. A delay in the results of the 2019 IRP by 15 months and the need for two major 2019 IRP amendments due to less than optimal results;

3. The Company requesting a waiver from its obligations to use Oregon Public Utilities Commission ("OPUC") Resource Procurement Rules adopted in Order No. 32745, listing time constraints as one of the primary justifications;[1]
4. The need to obtain firm transmission contracts to alleviate potential shortages to obtain market access to meet potential shortages starting in 2021;
5. Issuance of a 2021 Request for Proposal ("RFP") for immediate need of capacity starting in the summer of 2023 and the inability to obtain a rich pool of competitive bids that qualify due to timing. *See* Case No. IPC-E-22-13;
6. The possible issuance of a 2022 all-source RFP for capacity needs starting in the summer of 2024. *See* 2021 IRP at 172.

The above issues serve as a reminder of the importance of the IRP. Staff believes that when the Company reacts to acquire resources inside of resource acquisition lead times, the number of resource options and alternatives become limited resulting in increased cost to customers and potential for reliability issues.

The Company stated the immediate need for resources was due to "several dynamic and evolving factors" including: (1) increased load growth in the Company's service territory; and (2) changes in the Company's assumptions regarding market purchases due to lack of availability of 3rd party transmission.[2] *See* Application, Case No. IPC-E-21-41 at 2. Increased extreme weather events occurring in the Pacific Northwest and uncertainty in year-to-year water availability affecting hydro generation have also led to the need for immediate resources. *See* 2021 IRP - Appendix C at 99. It is these types of dynamic factors and risks that the IRP is intended to identify to prevent the resource acquisition lead-time issues that the Company is currently facing.

As a result, Staff's engagement during the 2021 IRP development cycle and its review of the final report was heavily focused on improvements to the Company's IRP processes, and the need to ensure system reliability. Staff's review for the 2021 IRP includes an analysis of the Company's methods to

---

[1] The case (IPC-E-21-41) was later withdrawn opting instead to file and qualify for an exemption with the OPUC to meet near term capacity shortfalls and filing for a Certificate of Public Convenience and Necessity ("CPCN") in Case No. IPC-E-22-13.

[2] The Company also stated changes in how the Company modeled reliability of its system that have been implemented in this IRP as an additional reason. The changes affected the amount of contribution of its resources, including its current Demand Response programs and how it identifies the hours critical for the need of additional capacity.

I. Measure and assure reliability of the Company's system;
II. Identify deficits through its L&R;
III. Develop resource portfolios and select the least cost least risk preferred portfolio;
IV. Determine the Company's natural gas forecast;
V. Verify assumptions for existing and future supply-side resources;
VI. Verify assumptions for existing and future demand-side resources;
VII. Include public participation in the Company's IRP process; and
VIII. Develop the Company's Action Plan.

I. Assurance of Reliability

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. Reliability is the primary constraint that the Company's resource plan must meet. Staff believes that the Company has improved the credibility of the timing and amount of future resource deficits reflected in its L&R and the ability of future resource portfolios to resolve future resource deficits. However, Staff has identified two concerns that the Company should address in the 2023 IRP:

1. The appropriateness of changing the LOLE reliability target to compensate for more frequent extreme weather events and uncertainty in year-to-year water availability affecting hydro generation availability;
2. Risks and inaccuracies caused by using a single benchmark year (2023) to determine the LOLE-based PRM.

A. Improvements to Assure Portfolio Reliability

In the 2019 IRP, the Company assumed that a 15% PRM was sufficient based on North American Electricity Reliability Corporation ("NERC") requirements and on PRMs used by other regional utilities.[3] It was not derived from a LOLE target like in this IRP. However, the Company performed a verification step in the 2019 IRP to determine if the preferred resource portfolio met a 1 day in 10-year ("1-in-10") LOLE,[4] but only verified it for the year 2025 without verifying any other years across the planning horizon. *See* Second Amended 2019 IRP at 126.

For the 2021 IRP, the Company developed and implemented reliability modeling functionality that was integrated with the Company's overall IRP methodology providing closed-loop verification that all high performing portfolios meet the Company's reliability target every year over the 20-year planning horizon. Instead of assuming a PRM is sufficient, the Company's new process allows the Company to determine a PRM from a LOLE target established at the beginning of the IRP cycle. Staff believes that these modeling improvements have improved the likelihood that the Company's resource portfolios will meet reliability requirements based on the LOLE goal.

To understand the new reliability modeling functionality, it is necessary to understand the overall process before the new functionality was added in this year's IRP. The backbone of the Company's IRP process uses two modules built into the Aurora modeling software: the LTCE module and the production cost simulation module. Both Aurora modules are integrated, allowing the Company to build a common model that represents the topology of the Company's current system. After a model of the Company's current system has been built, the LTCE functionality fills capacity deficits with resources selected from a pool of potential resources to produce a cost-optimized resource portfolio within a set of constraints; the most important constraint ensures that the portfolio has sufficient resources to meet customer load plus an additional PRM as a safety factor. By changing the inputs in the LTCE model, the Company can generate multiple alternative resource portfolios, which are cost optimized for a given set of inputs.

After resource portfolios have been produced, they are simulated through the production cost module. This module performs a time-step simulation that simulates the operation of the portfolio, dispatching the resources in the most cost-effective manner and within operational constraints of the resources included in a resource portfolio. As the production cost module steps

[3] The planning margin is an adjustment factor for the level of reserves needed to reliably meet load. It is added to the peak load forecast that determines the level of resources needed overall. The 2019 IRP used a PRM of 15% because it is consistent with the NERC's N-1 Reserve Margin criteria, which is similar to the planning margins used by other utilities in the same region. Page 103 of the Second Amended 2019 IRP.

[4] LOLE or Loss of Load Expectation is measured in days per year. A 1-day in 10-year LOLE is equivalent to 0.1 days of electricity outage that customers will experience each year.

through the 20-year planning horizon in simulated time, the software collects cost and performance data for a given portfolio and set of input assumptions. It is through the production cost module that the net present value ("NPV") for each portfolio is determined to inform the selection of a least-cost, least-risk portfolio.

The new reliability model developed for this year's IRP was integrated into Aurora by designing it to provide the PRM and ELCC[5] of variable renewable resources and time-limited[6] resources as inputs into the Aurora LTCE model. The PRM and the ELCCs generated as outputs by the new model are probabilistically determined to meet a desired LOLE reliability target. After the portfolios have been generated in the LTCE, the reliability model is used to verify that portfolios have met the LOLE target for all 20 years of the planning horizon as closed-loop verification.

In addition to the new reliability modeling functionality, the Company verified and updated the ELCC assumptions it used for its dispatchable resources. The Company utilized the Equivalent Forced Outage Rate ("EFOR") method to perform its updates which is based on the availability of the resources without forced downtime, like the methods used in past IRPs. The Company used recent historic data and incorporated recent upgrades to its facilities in its updates.

Staff believes the new functionality and steps the Company took to verify the load serving assumptions of resources improves the Company's ability to ensure an accurate measurement for the reliability of its resource portfolios in this year's IRP. However, Staff is concerned the Company's method uses only a single year (2023) as a benchmark to calculate the 15.5% PRM for all years of the planning horizon. Staff recommends the Company provide justification and additional analysis of other years to verify using only a single year in the 2023 IRP is appropriate.

---

[5] ELCC or Effective Load Carrying Capability is becoming the industry standard term used to describe the peak serving capability of resources. However, the method used to determine it depends on the type of resource.

[6] Time-limited resources includes energy storage and demand reduction which required additional functionality to model its ELCC.

B. Establishment of the Reliability Target

The Company applied a 15.5% PRM to its load forecast to develop the Company's portfolios. This 15.5% PRM was derived using a one day in twenty years ("1-in-20") or 0.05 days per year LOLE reliability target using the new reliability modeling capability described above. However, the Company changed its target 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 toward the end of the cycle. According to the Company, this reliability target was changed to account for the extreme weather events that are becoming more frequent and adding increased uncertainty in year-to-year water availability impacting hydro generation.[7] *See* 2021 IRP, Appendix C at 99.

A 1-in-10 LOLE target is the industry standard for resource planning as established by the NERC. *See* Response to Staff Production Request No. 14 in Case No. IPC-E-21-43. In addition, a 1-in-10 LOLE is used as the reliability standard for the California Independent System Operator Corporation[8] and for the Northwest Power Pool's Resource Adequacy Program.[9]

Staff believes 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. Instead of using a more stringent target to compensate for the variability of weather, 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.

Staff does not believe changing the LOLE target affected the overall results. The development of the Company's IRP can require the Company to rework its analysis as issues are discovered. The IRP is a serial process with many of the initial steps occurring several months before results can be obtained. When issues are discovered late in the process, options to make adjustments before the IRP is due may be limited.

---

[7] In Response to Staff's Production Request No. 15, the Company stated that Northwest Power and Conservation Council used a 1 day in 20-year LOLE in its Seventh Power Plan (https://www.nwcouncil.org/reports/seventh-power-plan) and in its Resource Adequacy site (https ://www. nwcouncil.org/energy/energy-topics/resource-adequacy).

[8] http://www.caiso.com/Documents/Mar14-2022-OpeningComments-Loss-LoadExpectationStudy-LCR-FCRSchedule-LocalCapacityRequirements-WorkingGroupReport-R21-10-002.pdf

[9] https://www.westernpowerpool.org/private-media/documents/2021-08-30_NWPP_RA_2B_Design_v4_final.pdf

In a meeting with Staff, the Company illustrated how weather variability over a historic four-year period had an impact on the resources needed to ensure reliability. By comparing the 2023 benchmark year resource requirement with average weather to the resource requirement for 2023 adjusted for weather over a recent four-year period, the Company demonstrated shortages could occur in two out of the four years. *See* Response to Production Request No. 20 in Case No. IPC-E-21-32. This indicates that the load forecast may be underestimated, or hydro resource capacity contribution overestimated (or some combination of both) during certain years over the IRP planning horizon by not accounting for year-to-year variability in weather. Given that the resulting 15.5% PRM is close to the 15% PRM used in previous IRPs, Staff believes that using a more stringent 1-in-20 LOLE target achieves approximately the same result and does not harm the overall results of the IRP. Although Staff does not believe that changing the reliability target is proper to compensate for adjustments needed in its model input assumptions, the change effectively ensured sufficient resources in the Company's final portfolios and allowed the Company to meet its schedule. Staff recommends the Company determine an alternative, other than changing the reliability target, to adjust for year-to-year variability in weather and water and to identify a reliability target based on customer tolerance of outages at the beginning of the 2023 IRP cycle.

II. 2021 IRP L&R

Because of the significant change in the first deficit dates between the 2019 IRP and the 2021 IRP, Staff compared the L&R in each IRP to understand drivers of the changes to determine if the L&R in this IRP is reasonable. The 2019 IRP had a first deficit date of August of 2029[10], while the 2021 IRP stated a first deficit date of July of 2023 with deficits also occurring in 2021 and 2022 in the Company's L&R.[11] Staff's analysis identifies the primary causes for the shift broken down by changes in the Load Forecast and in the existing resources.

[10] See Response to Staff's Production Request No. 92 in Case No. IPC-E-19-19. Based on this response, the first deficit based on the Second Amended 2019 IRP will occur in August of 2029 with a deficiency of 5 MW. However, the Application in Case No. IPC-E-21-09 (the first capacity deficiency case after the acknowledgement of the Second Amended 2019 IRP) stated that the first deficit will occur in August of 2028 with a deficiency of 14 MW. For the purpose of Staff's comments, the L&R with the first deficit year of 2029 is used to represent the results of the Second Amended 2019 IRP.

[11] See Table 10.7 in the 2021 IRP. The table also shows deficits in 2021 and 2022. Response to Staff's Production Request No. 32 in Case No. IPC-E-21-09 states that the deficits amounts in these two years were determined using the same method as the later years, but the 2021 IRP did not add resources in these years because the AURORA model was prevented from selecting resources due to the lack of lead time.

After reviewing of the Company's L&R, and quantifying the drivers causing the changes in the deficit dates, Staff believes that the L&R in the 2021 IRP is reasonable.

A. Load Forecast

The Peak Load Forecast in the L&R is the same forecast used to determine future resources in the preferred portfolio. The Peak Load Forecast was derived from the four main drivers impacting the load forecast in the 2021 IRP: (1) a higher migration of customers into the Company's service territory, (2) growth in the number of industrial customers, (3) a higher PRM, and (4) lower capacity contribution of existing DR programs.

During and after 2020, approximately 30% more people moved into the Company's service territory than expected. 2021 IRP at 170. Several industrial customers have also made binding investment and/or expressed interest to expand their operations in the Company's service territory.[12]

The Company's new reliability modeling functionality also highlighted the need to change the design of the Company's DR programs. The capacity contribution of existing DR programs was 390 MW for the entire planning horizon in the 2019 IRP. *See* Response to Staff's Production Request No. 92 in Case No. IPC-E-19-19. However, by measuring the capacity contribution of existing DR programs using the new reliability model, the Company discovered that the contribution of capacity was only 176 MW. *See* 2021 IRP (Table 10.7).

B. Resources in the L&R

On the resource side, Staff identified two primary factors that contribute to an earlier first deficit year: (1) reductions of capacity contribution of coal and natural gas plants (including Bridger, Valmy, and natural gas peakers); and (2) reductions in assumed market availability due to transmission capacity.

The 2021 IRP modeled dispatchable resources using a monthly outage table based on the resource's monthly capacity and EFOR. The use of EFOR and additional refinements made to the peaking capabilities of coal and natural gas resources resulted in reductions of capacity contribution of coal and the natural gas peaker resources.[13] *See* Response to Staff's Production

[12] For example, Brisbie, LLC's Data Center Facilities ("Brisbie") load is included in the L&R.

[13] Not all dispatchable resources reduced its capacity contribution under the new ELCC method. For example, the Hells Canyon Complex's capacity contribution increased by 60 MW under the new method. The method also

Request No. 9 in Case No. IPC-E-21-43. Table No. 1 reflects the change of capacity contribution for these resources.

Table No. 1: Comparison of Capacity Contributions between 2021 IRP and 2019 IRP

	Bridger (MW)	Valmy (MW)	Gas Peakers (MW)
2021 IRP	663	121	365
2019 IRP	703	136	416
Difference	-40	-15	-51

The second factor contributing to an earlier first deficit year was the reduction in market availability due to transmission capacity assumptions. In previous IRP's, the Company only constrained market availability by transmission capacity within its own system. It had always assumed firm transmission to market hubs could be obtained outside of its service territory. In addition, the Company assumed Valmy Unit 2 could be replaced with market purchases from the southern market in its 2019 IRP. As will be discussed in more detail later, firm transmission capacity became strained due to California's energy emergency in 2020. 2021 IRP at 168. Because of these developments, the Company constrained market availability by market hub access limited by third-party firm transmission reserved by contract. Response to Staff's Production Request No. 32 in Case No. IPC-E-21-09. Changes in assumptions for market availability due to changes in transmission assumptions contributed to an earlier first deficit year. Table No. 2 shows the change in market purchases (without B2H) from 2023 through 2029 based on the changes to transmission assumptions in this year's IRP.

changed how intermittent resources' capacity contribution is calculated. For example, solar contribution was calculated using the 8,760-based method developed by the National Renewable Energy Laboratory in the 2019 IRP, but now it is calculated by the ELCC method in the 2021 IRP. 2021 IRP at 51. Despite the method change, the capacity contribution of total PURPA resources (including solar, wind, and others) did not change much for the first half of the planning horizon.

Table No. 2: Comparison of Market Purchases in 2019 IRP and 2021 IRP

Market Purchases (MW)	2023	2024	2025	2026	2027	2028	2029
2021 IRP	710	709	707	705	704	703	702
2019 IRP	923	923	923	1054	1054	1054	1054
Difference	-213	-214	-216	-349	-350	-351	-352

III. Development of Portfolios and Selection of the Preferred Portfolio

Staff believes the Company identified a preferred portfolio that (1) resolves deficits in its L&R; (2) informs key resource decisions that need to be made within the next ten years; and (3) strikes a reasonable balance between cost and risk. Staff came to this conclusion by reviewing how the Company:

1. Verified its models were operating as expected and validated that the models produced cost-optimized portfolios for the Company's balancing area ("BA");
2. Developed and compared different resource portfolios based on key resource decisions; and
3. Evaluated the risk of competing portfolios.

The resulting preferred portfolio included in the Company's 2021 IRP was the Base with B2H portfolio. It projects the following changes in the Company's resources over the next ten years:

- Conversion of Bridger Units 1 and 2 from coal to gas-fired generation by the end of 2024;
- The addition of approximately 700 MW of wind in 2024;
- The addition of 1105 MW of solar from 2023 through 2029;
- The addition of 650 MW of storage from 2023 through 2031;
- The addition of 500 MW of market access through the B2H transmission line in 2026;
- About 340 MW of DR capacity with implementation of the new programs starting in 2022;
- Removal of 308 MW and 175 MW of coal plant capacity through exit of Valmy Unit No 2 at the end of 2025 and Bridger Unit No. 3 at the end of 2028, respectively; and
- The addition of about 256 MW of capacity contribution from Energy Efficiency ("EE").

2021 IRP at 152.

A. Verification and Validation of the Company's Models

Because of the extensive use of computer models involved in producing the Company's IRP, it is necessary for a comprehensive QA plan to perform both verification and validation to ensure that the models are behaving as conceptually designed and that the results produced are accurate. The Company made significant improvements in its QA efforts for both verification and validation in this year's IRP; however, Staff recommends the Company produce a comprehensive QA plan in its next IRP that lists all the items the Company verifies or validates in its models.

One of the most significant improvements was the verification and validation of the Aurora LTCE optimization module used in the 2021 IRP. In the 2019 IRP, the Company could only produce cost-optimized resource portfolios for the Western Electricity Coordinating Council ("WECC") interconnection and was not able to produce cost-optimized portfolios for the Company's BA. This issue caused the 2019 IRP to be delayed by 15 months and required the Company to perform manual steps to determine cost optimal portfolios for its system. However, because WECC-optimized results were used as a starting point for the manual adjustments, Staff was not assured that the manually adjusted portfolios were optimal.

The Company has since worked with Energy Exemplar, developers of the Aurora software, to make modifications that ensure the resource portfolios are optimized for the Company's BA. Staff believes that the LTCE module now produces results optimized for the Company's BA. *See* Company Response to Audit Request No. 2.

As described above, the Company also developed a process for verifying the reliability of the Company's portfolios back to the LOLE target used to establish the PRM used as an input in the LTCE models. The results of these tests found several capacity shortfalls in the last five years of the 20-year planning horizon that did not meet the LOLE reliability target. To ensure the NPV cost of all the portfolios were comparable, the Company added the cost of capacity to make up for any shortfalls in reliability using the cost per kilowatt-year of a Simple Cycle Combustion Turbine ("SCCT") capacity resource. Staff believes this was an appropriate adjustment because of the size and timeframe of the adjustments. *See* 2021 IRP, Appendix C at 99.

Finally, the Company performed sensitivity analyses by changing the resources in optimized portfolios to determine their effect on the cost of the portfolios. If the changes caused a decrease in the NPV cost of the portfolio, the Company could conclude that the original portfolio was not optimized. The Company tested key resource decisions such as: (1) different transfer capacities of B2H; (2) different exit dates of coal plants; (3) exiting Bridger Units 1 and 2 instead of a natural gas conversion; (4) replacement of solar plus storage with natural gas generation; (5) replacing dispatchable resources with geothermal and biomass; and (6) increased amounts of Demand-Side Management. In all cases, the LTCE optimized portfolios were least cost. Staff believes that these tests were key to validating the model results and improved the credibility of the IRP. Staff recommends the Company document all verification and validation QA steps in the same way these tests were documented in the 2021 IRP by describing the purpose of the test, how the test was conducted, and the results.

B. Development and Evaluation of Portfolios

The Company built six Base portfolios targeting important resource questions that needed to be answered in the 2021 IRP, the most important being whether or not to build the B2H transmission line. The Company included three Base portfolios with B2H and three without B2H. Within those two sets of portfolios, the Company generated portfolio variations on whether it was beneficial to align Bridger exit dates with PacifiCorp, and whether Gateway West was economical. Beyond these resource alternatives being forced into portfolios, all the remaining deficits were filled with resources that were the most economical by using planning conditions for all key inputs such as load growth, natural gas price, and carbon price. The Company then ran each Base portfolio through the production cost model to determine their NPV cost over the 20-year time horizon using different natural gas prices (planning and high) and carbon prices (zero, planning, and high). Staff believes this analysis was appropriate and informs of the need for the B2H transmission line given planning case input assumptions. The NPV results of the Company's Baseline analysis is duplicated from the Company's IRP as shown below.

2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$7,915,702	$7,186,761	$9,832,001
Base B2H PAC Bridger Alignment	$7,999,347	$7,152,955	$9,932,925
Base without B2H	$8,192,830	$7,784,545	$9,474,983
Base without B2H without Gateway West	$8,441,414	-	-
Base without B2H PAC Bridger Alignment	$8,185,334	$7,588,228	$9,652,891
Base with B2H—High Gas High Carbon Test	**$7,997,339**	-	**$9,424,935**

The NPV results show that the portfolios with B2H were least cost for planning gas and planning or zero carbon; however, the production cost simulations show that B2H may not be the most economical choice with high natural gas and carbon prices. Based on these results, the Gateway West transmission line without B2H may be more economical because Gateway West would provide better access to renewable energy. To counter this contention, the Company produced additional base portfolios including B2H (as shown on the bottom row of the table). Instead of using planning gas and carbon to develop the portfolios, it used high gas and carbon. Because of this analysis, the Company concluded:

> [The] "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

2021 IRP at 130, fn 36.

However, Staff does not agree with the Company's conclusion since these results 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.

C. Evaluation and Mitigation of Risk

The Company performed three general types of analysis to evaluate risk: (1) the generation of different portfolios given different alternative future scenarios; (2) a qualitative analysis of all the Base portfolios across several risk factors; and (3) a stochastic risk analysis where all Base portfolios were simulated through the production cost model and subjected to randomized values within a reasonable range of gas prices, loads, and hydro generation. *See* 2021 IRP at 121, 134, and 136. Based on the scoring of these risk evaluation methods, the Company determined the Base with B2H preferred portfolio has a comparatively low level of risk when compared to the Company's other Base portfolios. However, Staff has two concerns related to risk:

1. How much the Company is relying on B2H to meet its future capacity needs due to it being the largest and most expensive resource in the Company's preferred portfolio; and
2. The lack of risk mitigation and flexibility strategies included in the Company's IRP.

The Company analyzed several sensitivities of risk associated with (1) how much capacity the Company will be able to obtain through the B2H transmission line, (2) increases in B2H construction costs that would make the preferred portfolio no longer economic, and (3) the impact of not being able to meet the B2H in-service date by the end 2026. Because B2H represents the largest and most expensive single resource included in the preferred portfolio, there is additional risk if it does not meet budget and schedule and would likely cause serious impacts to both customer cost and reliability. According to the Company's analysis on construction costs, a cost overrun of more than 30% would need to occur for the Base with B2H portfolio to no longer be the lowest cost portfolio. In addition, if the in-service date extends by one year, the Company will need to acquire additional resources to fill capacity gaps estimated to cost an additional $69 million. 2021 IRP at 145-146. Staff does not believe that a cost overrun of 30% or a slip in schedule of one year is unrealistic given current rates of inflation and supply chain issues that may persist into the future, as well as, transmission siting issues that have historically been difficult for the Company to resolve.

Staff is also concerned that the Company's IRP does not examine a strategy of resource flexibility that could proactively mitigate a rapidly changing energy environment. The Company included plans to convert Bridger Units 1 and 2 to natural gas. However, the facility was not consciously designed for rapid conversion requiring extensive downtime and cost. Staff believes the Company should study ways to include resources that provide flexibility to changes due to regulations, fuel costs, customer behavior, economic drivers, electricity markets, and other factors. These solutions could include: resource diversity,[14] multi-fuel thermal plant designs (i.e., plants that can burn hydrogen, natural gas, coal gas, etc.), scalable/modular approaches to decreasing or increasing capacity, mobile generation that can be moved to constrained load pockets until more permanent solutions are constructed, mothballing coal plants instead of decommissioning, and improving access to multiple market hubs, are just a few examples. Proactively designing a flexible supply chain carries additional cost, which is why Staff recommends it should be studied in the 2023 IRP.

IV. Natural Gas Forecast

Historically, natural gas price forecasting within the Company's IRP has been controversial. For the 2013 and 2015 IRP natural gas price forecasts, the Company used the EIA's Henry Hub reference case forecast, adjusted for Sumas basin pricing. This method reflected the Company's city gate price for natural gas. In 2017, the Company departed from using the EIA's Henry Hub reference case and used the EIA's Henry Hub High Oil and Gas Resource and Technology Case. This method produced low natural gas prices throughout the IRP 20-year planning period and prompted intense discussions within IRP stakeholder meetings calling for improvement in how the Company forecasts IRP natural gas prices.

The Company continued efforts toward making improvements to its IRP natural gas price forecasting. In 2019, the Company decided to use a third-party vendor for its IRP natural gas price forecast and selected S&P Global Platts North American Gas Analytics ("Platts") and used Platts again in the 2021 IRP.

Through analysis of the impact of higher gas prices on the IRP, the Company used the EIA's Low Oil & Gas Supply forecast from EIA's Annual Energy Outlook 2021. The EIA's Low Oil & Gas Supply assumes lower oil and gas production, which creates a higher natural gas price.

[14] Because of the optimization algorithms in the LTCE model, the model tends to select the lowest cost resource available for selection by the model to fill deficits that can dominate portfolios.

The Company stated:

> To verify the reasonableness of the third-party vendor's forecast, Idaho Power compared the forecast to Moody's Analytics, the United States Energy Information Administration (EIA), and the New York Mercantile Exchange (NYMEX) natural gas futures settlements. Based on a thorough examination of the forecasting methodology and comparative review of the other sources (i.e., Moody's, EIA, and NYMEX), Idaho Power concluded that the third-party vendor's natural gas forecast is appropriate for the planning case forecast in the 2021 IRP.

2021 IRP at 105.

Staff believes the Company's analysis and utilization of EIA, NYMEX, and Moody's data to verify that Platts' forecast is appropriate for planning purposes and use of the forecast in the IRP is reasonable. Given current natural gas price volatility, Staff encourages the Company to continue to monitor its natural gas price forecasts and market conditions. Staff supports the Company's natural gas forecasting improvement efforts and believes changes to generation resources and portfolio selections are important considerations in further development of forecasting methods to minimize fuel price risk and operating costs.

V. Supply-Side Resources

<u>A. Transmission and Market</u>

Staff recognizes the potential benefit of the Company's transmission system for providing interconnecting capacity and for accessing low-cost energy from the market. But unless the Company has secured firm access through interconnecting transmission, the benefit to its system can disappear quickly. This can be seen following the recent events in 2020. As a result, the Company opted to reduce its access transmission capacity for the years 2023 through 2025 from 900 MW in the 2019 IRP to 700 MW in the 2021 IRP, resulting in immediate need for new generation resources by 2023.

Staff believes its reasonable for the Company to expand its share of B2H to 45%. The Company states that it continues to expand its transmission resources to bring low-cost hydro and renewable variable energy resources ("VERS") into its service area. In this IRP, the Company expanded its share of the B2H transmission, planned for completion in 2026, from 21% in 2019 to 45% in the 2021 IRP. The Company's increase is reflected through its absorption of Bonneville Power Administration's previously assumed ownership share. Given this addition and its associated cost, the inclusion of B2H in the 2021 IRP analysis showed a

NPV benefit of $270 million compared to the next least-cost alternative portfolio which did not include B2H.

In 2020, the Company's transmission system allowed it to purchase 7.4% of its energy need through the market at lower relative cost. Although transmission can provide significant economic benefit when low-cost energy is available, Staff believes there are certain risks to the system. As external factors evolve, the risk for the Company's investment in transmission becomes more apparent.

In the 2019 IRP, the Company assumed Valmy Unit 2 could be replaced with capacity purchases from the south, but market conditions changed after the August 2020 California energy emergency event. The event caused a ripple effect limiting the Company's ability to secure third-party firm transmission to import energy. While the Company directly maintains its ability to reserve its own transmission, it must rely on transmission interconnections from adjacent BAs to benefit from lower cost market purchases.

B. Hydro Resources

The Company has a stated goal for sourcing 100% of its electricity through clean generating resources. Staff is concerned that as the Company relies more heavily on hydro generation and renewables to step away from more traditional dispatchable resources increasing reliability risk to the system.

Idaho Power plans to utilize hydropower generation as its main tool for meeting the Company's goal of selling 100% clean energy by 2045. Idaho Power's hydroelectric generation currently comprises 42% of the Company's total generating capacity. Any significant yearly reduction in hydroelectric generation or a change in the timing of yearly runoff can negatively affect system reliability and would create upward pressure on rates during low hydro periods especially as the Company moves toward more intermittent renewable resources. As noted in the 2021 IRP climate study, change and specific risks are an evolving category that include changes in customer usage and hydro generation from changing weather conditions.

The climate change study indicates natural hydrographs could see lower summer base flows, an earlier shift of the peak runoff, higher winter baseflows, and an overall increase in annual natural flow volume. For Idaho Power's hydro system, the findings support that upstream reservoir regulation, if available, could significantly dampen the effects of this shift in natural flow to Idaho Power's system. Staff believes it is unlikely that additional upstream reservoir regulation will occur. Further, the studies indicate Idaho Power could actually see July through December regulated streamflow relatively unaffected, and January through June regulated stream flows increase over the 20-year planning period.

For the 2021 IRP, the Company showed no reduction to the available capacity or operational flexibility of its hydroelectric plants, although over the long term, the variability of stream flows may or may not support the trend in hydro generation during peak summer load.

C. Coal Generation

Staff believes existing coal generation is an effective resource for providing dispatchable generation, and currently provides system reliability. Coal contributes about 21% of the energy delivered to the Company's customers. As the Company transitions towards its clean energy goal, the Company needs to be strategic in the timing of coal unit exits. The timing of coal unit exits and replacement with new resources significantly impact customer rates and without proper planning may impact system reliability.

In the 2021 IRP, Idaho Power continued to analyze exiting from coal units before the end of their depreciable lives. These coal units continue to deliver generating capacity and energy during high-demand periods and/or during periods of high wholesale-electric market prices.

The 2021 IRP reflects different thermal resources exit dates with the Company exiting all coal generation by 2028 -- two years earlier than the final coal exit date in the 2019 IRP. PacifiCorp and the Company concluded through their IRPs, it would be cost-effective to convert Bridger Units 1 and 2 to natural gas beginning in 2024 while continuing to operate Units 3 and 4 as coal units. This would be the only natural gas addition in the 2021 IRP -- compared to 411 MW of new gas generation added in the 2019 IRP.

In the 2021 IRP, the Company plans to exit coal operations for Bridger Unit 3 at the end of 2025 and Unit 4 at the end of 2028 and completely exit the plant in 2034 while PacifiCorp would continue to operate Units 3 and 4 through 2037. Staff understands that neither partner has developed contractual terms necessary to allow for the potential earlier exit or conversion to a non-coal fuel source. Because of the lack of a Bridger exit agreement with PacifiCorp like the exit agreement developed for the closure of Valmy, the Company has not been able to include potential costs of extending or exiting operations early. Without this agreement, the economic evaluation of different exit dates is probably inaccurate in this IRP. Staff believes 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.

Following development of the 2019 IRP, the Company conducted focused system reliability and economic analyses to assess the appropriate timing of a Valmy Unit 2 exit between 2022 and 2025. The result of the reliability and economic evaluations demonstrated that coal-fired operations at Valmy Unit 2 through the end of 2025 is the most reliable and economic path forward.

The obligation to deliver reliable and affordable electricity underscores its need to continue to evaluate coal unit value for providing flexible capacity necessary to successfully integrate the high penetration of VERs. Staff believes the Company is responsible for the evaluation of flexible capacity and the possibility of flexible resource capacity deficiencies arising because of coal-unit exits, which may require the Company to extend coal-unit operations to maintain system reliability.

D. Renewable Energy and Energy Storage

Staff is concerned by the Company's transition toward VERs and energy storage in the 2021 IRP as compared to the 2019 IRP. The 2021 Preferred Portfolio adds sizeable amounts of VERs totaling 700 MW of wind and 1,405 MW of solar during the forecast period. The Company also plans to add 1,685 MW of battery energy storage during this period. In contrast, the 2019 IRP Preferred Portfolio included no wind resources, 400 MW of solar, and only 80 MW of battery storage. Most of the Company's renewable resources come online prior to 2030.

Staff recognizes the benefit of zero-fuel cost VERs, but as the Company works toward its clean energy goal, 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.

E. Natural Gas Generation

The Company stated that Langley Gulch will be upgraded in 2022 and the total nameplate of the plant will increase to 365 MW. All of the Company's natural gas facilities are used as needed to support system load. Natural gas generation provides approximately 15% of the Company's electricity.

The 2019 IRP included 411 MW of additional natural gas generation, but this IRP includes no new natural gas generation additions. Notably, the Company is working with PacifiCorp to convert Bridger Units and 1 and 2 from coal to natural gas. The cost of conversion is significantly less than installing Selective Catalytic Reduction ("SCR") on coal fired units to comply with federal Regional Haze regulations. Additionally, Staff believes having two additional dispatchable gas peaker units provides system benefits for both companies and was shown to be cost effective compared to other alternatives for additional capacity due to the low capital cost of conversion. The gas conversion of Bridger should be online during the summer of 2024 -- with an exit date of 2034 -- providing 357 MW of electricity.

The conversion of Bridger Units 1 and 2 to natural gas provides operational, reliability, and economic benefits. However, 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.

VI. Demand-Side Resources

A. EE

In the 2019 IRP, the Company utilized the Total Resource Cost ("TRC") test resulting in a 20-year EE potential of 234 average megawatts ("aMW"). However, the Commission denied the Company's request to use the TRC perspective during the integrated resource planning phase and ordered the Company to use the Utility Cost Test ("UCT") perspective for integrated resource planning. Order No. 34469 at 9. With the change to the UCT, the Company's EE potential increased to 300 aMW or 440 MW over the 20-year planning horizon. Staff believes the use of the UCT perspective will result in a more accurate IRP forecast for EE and will help align the Company's current EE programs, currently evaluated using the UCT, with IRP EE forecast.

The 440 MW consists of 428 MW of EE determined by cost-effective measures identified in the EE Potential Assessment, conducted by Applied Energy Group, and 12 MW of EE selected by Aurora. The 12 MWs of EE measures selected by Aurora were considered cost-ineffective through the Potential Assessment; however, the additional 12 MWs of EE across the 20-year planning horizon were selected by Aurora based on economic parameters for a single year. To allow the model to select additional EE for any given year, the Company bundled similar cost-ineffective EE measures into four groups based on their cost and peak seasonal load shapes: (1) summer low cost; (2) summer high cost; (3) winter low cost; and (4) winter high cost. The Company then allowed Aurora to select additional EE bundled measures as their own resource in any given year. This resulted in EE bundles of 3 MW and 9 MW being selected in 2039 and 2040. 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.

B. DR

During the development of the 2021 IRP, to better align the existing programs with system needs, the Company modified its existing DR programs to remove marketing limitations, adjust incentive levels, adjust hours of use, and extend the season for all three of their DR programs. *See* Case No. IPC-E-21-32. The modifications resulted in the Company planning on an estimated 300 MW of nameplate capacity from the modified programs in the 2021 IRP.

For estimating the potential of DR in the 2021 IRP, the Company used the "Northwest Power and Conservation Council ("NWPCC") assessment of DR potential for the Northwest region to determine the DR potential that may be available in Idaho Power's service area." 2021 IRP at 68-69. After several adjustments[15] to the NWPCC assessment of DR, the Company estimates an additional 280 MWs of available DR capacity in its service territory, which was divided into 20 MW bundles, to be selected by the LTCE model. In the 2021 IRP preferred portfolio, the LTCE selected an additional 100 MW of DR capacity in addition to the 300 MW from the modified programs, with 20 MW additions in 2023 and 2025. Comparatively, the Company's existing DR programs provided 390 MW of peak capacity and the LTCE selected an additional 45 MW of DR in the 2019 IRP preferred portfolio.

DR can be a valuable resource in helping the Company offset loads during system peak. Staff is concerned that the 20 MW threshold capping additional DR capacity in the LTCE model may limit the addition of new DR capacity when the Company is capacity deficient, i.e., the Company is currently forecasted to be capacity deficient in the summer of 2023. Staff recognizes that a threshold cap is likely necessary to implement for additional DR capacity due to ramping issues with new DR programs but recognizes the benefits DR can provide in helping

[15] For information on the Company's adjustment to the NWPCC DR potential assessment to their service territory, *See* Staff Comments at 5 on IPC-E-21-32.

the Company in times of capacity constraints. Therefore, Staff recommends the Company discuss and explore adjusting the 20 MW threshold cap on additional DR capacity with its Energy Efficiency Advisory Group and the IRPAC in the development of the 2023 IRP.

With the recent modifications to existing DR programs, Staff notes that the 300 MW from the modified DR programs is merely an estimate and participation numbers could be highly variable resulting in higher or lower than planned DR capacity. Prior to the modifications, the existing DR programs maintained consistent participation and the Company could regularly plan on approximately 390 MW of DR potential during their IRP planning periods. With the major changes to the DR program, expanding dispatchable hours later in the evening and extending the program season to address higher risk hours for reliability, the participation amounts in the modified programs could vary. Staff recommends the Company continuously monitor existing DR program participation and adjust estimates for available DR capacity accordingly as the Company learns of customer's willingness to participate in the modified DR programs.

The Company is currently conducting a DR potential study for its service territory that will be included in the 2023 IRP. The results of the DR potential study will improve the accuracy of DR potential for the Company's service territory.

VII. Public Participation

The Company held nine virtual IRPAC meetings that were open to the public, and three additional workshops to address questions specific to different aspects of the IRP.

The virtual format of the meetings allowed for increased levels of participation by allowing meeting participants to ask questions during presentations. By using the chat function, other members of the Company's IRP team were able to address a larger number of the questions from the public.

The largest improvement Staff saw in its engagement in the process was the level of active listening and engagement that took place by the Company's IRP team. Input was well received and recorded, and questions were validated with responses provided later if answers were not immediately available.

VIII. Action Plan

The action plan from the 2021 IRP is developed to address actions the Company needs to implement within the 2021 to 2027 action plan window. Because the Commission only acknowledges the IRP, Staff believes that most of the resources included in its IRP portfolios should be considered as proxies. To obtain Commission approval requires additional process and subsequent filings to ensure determination of prudence of specific resources before cost recovery occurs.

To evaluate prudence classified as proxies, Staff believes 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. This cannot be accomplished if the pool of proposals is unnecessarily limited in scope. Staff encourages the Company to only limit proposals based on a minimum and critical set of specifications and resource characteristics in scoping its RFPs.

However, there are specific existing resources nearing end of life and specific transmission resources included in the Company's preferred portfolio that do not fit within the definition of a proxy resource. The action plan for these types of resources will need actions to evaluate how to move forward rather than comparisons of proxies through an RFP.

Staff believes that most of the items within the Company's action plan are reasonable; however, Staff cautions that some actions, such as the acquisition of solar and wind during specific years should be re-evaluated in the context of a broadly-scoped RFP.

STAFF RECOMMENDATIONS

Staff recommends that the Commission acknowledge the Company's 2021 IRP and address the following in the Company's 2021 IRP action plan:

1. Re-evaluate its action plan to not include acquisition of specific types of resources where a broadly scoped RFP is appropriate; and
2. Develop a Bridger exit agreement with PacifiCorp that determines potential costs of extending or exiting operations early similar to the exit agreement developed for the closure of Valmy and incorporate those costs into its coal plant exit costs to properly value different exit dates in its 2023 IRP.

Staff also recommends the Company address the following in the 2023 IRP:

1. Incorporate extreme weather events and variability of water availability through its load and resource input assumptions, rather than compensating by changing the LOLE reliability target, which should be set as a matter of public policy;

2. Only include market access backed by firm transmission reservations in its L&R;
3. Evaluate the risks and inaccuracies caused by using a single benchmark year (2023) to determine the LOLE-based PRM;
4. Provide a comprehensive QA plan to verify and validate its models by describing the purpose of each test, how the test was conducted, and the result; and
5. Study the costs and benefits of implementing a flexible resource strategy.

Respectfully submitted this 2[ND] day of June 2022.

Dayn Hardie
Deputy Attorney General

Technical Staff: Mike Louis
Kevin Keyt
Taylor Thomas
Yao Yin
Rick Keller

i: umisc/comments/ipce21.43dhmlkskttyyrkjh comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 2ND DAY OF JUNE 2022, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-21-43, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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

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

KIKI LESLIE A. TIDWELL
704 N. RIVER ST. #1
HAILEY ID 83333
E-MAIL: ktidwell2022@gmail.com

BENJAMIN J OTTO
EMMA E. SPERRY
ID CONSERVATION LEAGUE
710 N 6TH ST
BOISE ID 83702
E-MAIL: botto@idahoconservation.org
esperry@idahoconservation.org

PETER J RICHARDSON
RICHARDSON ADAMS PLLC
515 N 27TH STREET
BOISE ID 83702
E-MAIL: peter@richardsonadams.com

DR DON READING
6070 HILL ROAD
BOISE ID 83703
E-MAIL: dreading@mindspring.com

KELSEY JAE
LAW FOR CONSCIOUS LEADERSHIP
920 N CLOVER DR
BOISE ID 83703
E-MAIL: kelsey@kelseyjae.com

MICHAEL HECKLER
COURTNEY WHITE
CLEAN ENERGY OPPORTUNITIES FOR IDAHO INC
3778 PLANTATION RIVER DR
SUITE 102
BOISE ID 83703
E-MAIL:
mike@cleanenergyopportunities.com
courtney@cleanenergyopportunities.com

AUSTIN RUESCHHOFF
THORVALD A NELSON
AUSTIN W JENSEN
HOLLAND & HART LLP
555 17TH ST STE 3200
DENVER CO 80202
E-MAIL: darueschhoff@hollandhart.com
tnelson@hollandhart.com
awjensen@hollandhart.com
aclee@hollandhart.com
glgarganoamari@hollandhart.com

JIM SWIER
MICRON TECHNOLOGY INC
8000 S FEDERAL WAY
BOISE ID 83707
E-MAIL: jswier@micron.com

JACK VAN VALKENBURG
VAN VALKENBURG LAW PLLC
PO BOX 531
BOISE ID 83701
E-MAIL: jack@vanvalkenburghlaw.com

JIM KREIDER
STOP B2H COALITION
60366 MARVIN RD
LA GRANDE OR 97850
E-MAIL: jim@stopb2h.org

Jo Nelson
SECRETARY