ORDER NO. 21-184

ENTERED Jun 04 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 74

In the Matter of IDAHO POWER COMPANY, 2019 Integrated Resource Plan.	ORDER

DISPOSITION: 2019 IRP ACKNOWLEDGED

This order memorializes our decision, made and effective at the April 15, 2021 Special Public Meeting, concerning Idaho Power Company's 2019 Second Amended Integrated Resource Plan (IRP). We acknowledge all action items proposed in Idaho Power's revised action plan with the exception of the items discussed below. In addition, we adopt many of Staff's additional recommendations, modifying some action items as described in Staff's report, most of which are applicable to Idaho Power's forthcoming 2021 IRP.

I. INTRODUCTION

Through this IRP process, we reviewed a series of actions Idaho Power intends to take for the long-term provision of service to customers. These decisions include both removal of resources from its portfolio, such as exits from coal facilities, and development and acquisition of new resources. We acknowledge Idaho Power's early exit from coal facilities as reasonable given IRP modeling results, though we accept that further near-term analysis could lead Idaho Power to modify the timing of its actions. We acknowledge Idaho Power's Boardman to Hemingway (B2H) transmission project action items, as we also did in Idaho Power's 2017 IRP. We also accept, as has Idaho Power, many recommendations from Staff for additional analysis and review as part of the 2021 IRP.

II. IRP PROCESS

A. Purpose

The objective of the IRP process is to ensure an adequate and reliable supply of energy at the least cost to the utility and customers in a manner consistent with the public interest.[1]

---

[1] *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 2 (Apr 20, 1989).

The IRP process provides an extensive opportunity broad input from a range of stakeholders and public participation. This input and IRP guideline requirements are meant to ensure a detailed and wide-ranging review of resource options, technology advancements, pricing scenarios, and risk profiles, and to test the utility's conclusions. The IRP process is intended to be iterative. Where weakness in the analysis or issues are identified, stakeholder participation can help identify alternatives and improvements to the action plan or analysis in the next IRP. Utilities should respond proactively to the concerns of stakeholders, and consider alternatives.

Ultimately, an acknowledged plan will become a working document for use by the utility, the Commission, and other interested parties in Commission proceedings.[2] We have noted in recent IRP decisions that during a time of considerable electric utility industry transition, IRPs should serve to allow for course corrections as industry evolution comes into greater focus.[3]

B. Timing and Content

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan.[4] The IRP process uses a 20-year planning period. Oregon's IRP guidelines include thirteen elements. Summarized, the elements are: (1) Identification of capacity and energy needs to bridge the gap between expected loads and resources; (2) Identification and estimated costs of all supply-side and demand-side resource options; (3) Construction of a representative set of resource portfolios; (4) Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; (5) Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and (6) Creation of an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

The primary outcome of the IRP process, after the presentation of the plan and review by Staff and stakeholders, is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and the customers, culminating in a Commission acknowledgment decision that indicates whether the Commission deems reasonable the plan overall and any specific action items.

---

[2] *Id.* at 7.
[3] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan, Docket No. LC 66*, Order No. 17-386 at 2 (Oct 9, 2017).
[4] OAR 860-027-0400(3).

C. Action Plan

An important product of the IRP process is an action plan. Where the preferred portfolio calls for new supply-side and demand-side resources or resource actions to meet system needs, the action plan will include these resource actions. The action plan identifies the steps the company will take within the next four years to deliver resources identified in the preferred portfolio of resources. Different resources require different actions on different timelines. Transmission, in particular, requires more development lead-time than other supply-side resources.

D. Acknowledgment

Our acknowledgment of an IRP means that the Commission finds that the utility's preferred portfolio and action plan is reasonable at the time of acknowledgment.[5] We may decline to acknowledge specific action items if we are not satisfied that the proposed resource decision presents the least cost, least risk option for customers. We may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.[6]

Acknowledgment is not a guarantee of cost recovery, nor is consistency with an acknowledged plan a requirement for recovery of resource costs in rates. Acknowledgment provides guidance for later ratemaking proceedings, which are the forum for the Commission to make its ultimate decision to approve or disapprove a resource procurement as prudent and subject to recovery in customer rates. Consistency with an acknowledged plan may be used as evidence in support of favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable, particularly in light of any material changes in the facts, circumstances, and assumptions that supported IRP acknowledgment.

III. DISCUSSION

In its Second Amended 2019 IRP, Idaho Power requested the acknowledgment of 14 action plan items. Staff proposed some modifications to Idaho Power's action plan items and additional recommendations for Idaho Power's next IRP, which we adopted except where described below. Below, we review action items and other issues in the same order and groupings as was discussed during the April 15, 2021 Special Public Meeting.

---

[5] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at 16 (Jan 8, 2007).

[6] OAR 860-027-0400(6).

A. Items Recommended for Non-Acknowledgment by Staff

1. Jackpot Solar

In action plan item no. 12, Idaho Power requested the acknowledgment of the 120 MW Jackpot Solar project, scheduled to be online by December of 2022. On March 22, 2019, Idaho Power and Jackpot Holdings, LLC entered a 20-year Power Purchase Agreement (PPA) for the purchase and sale of 120 MW of solar electric generation from the Jackpot Solar facility located north of the Idaho–Nevada state line near Rogerson, Idaho. Under the terms of the PPA, Idaho Power will receive all renewable energy credits from the project. An application was submitted to the Idaho Public Utility Commission (IPUC) on April 4, 2019, requesting an order approving the PPA, and on December 24, 2019, the IPUC issued Order No. 34515 approving the Jackpot Solar PPA. On the same day as the IPUC application, Idaho Power submitted a notice to this Commission, in accordance with OAR 860-089-0100 (3) and (4), of an exception from Oregon's competitive-bidding requirements for electric utilities as the PPA with Jackpot Holdings, LLC presented a time-limited opportunity to acquire a resource of unique value to Idaho Power customers.

a. Stakeholder Positions

The Oregon Citizens' Utility Board (CUB) believes that Idaho Power is requesting this Commission's acknowledgment of an investment that has already been made, because Idaho Power had already signed the PPA and is obligated to purchase the power when it becomes available, resulting in the project being "substantially complete." CUB argues it is inappropriate for an executed PPA to be included in a list of action items for acknowledgment, because an acknowledgment would be in part a judgment of the prudence of the action.

CUB does not dispute that the execution of this PPA is a proper use of the OAR 860-089-100(3)(b) exception to our competitive bidding guidelines. Similarly, CUB is not making a judgment regarding the prudence of the company's action in executing the PPA at this time. Instead, CUB argues that we have a precedent of not acknowledging action items that have already occurred, and that a request to acknowledge an action item that has already occurred, is in effect, a request for a prudence determination in an IRP.[7] As a result, CUB argues we should not acknowledge this action item.

[7] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252 (Jul 8, 2014)

STOP B2H supports the Jackpot Solar project, and we discuss STOP B2H comments on the project below in our review of the B2H project, as they are most relevant in that discussion.

Staff is concerned with the Commission acknowledging a project for which a utility has already requested a waiver of competitive bidding rules and, therefore, recommends not acknowledging this project. Staff agrees with CUB and STOP B2H that the project does appear to be a cost-effective opportunity but also agrees with CUB that it would be inappropriate for us to acknowledge. Staff states Idaho Power should feel free to pursue cost recovery on this project in a rate case without acknowledgment.

In opening comments to the Amended IRP, Idaho Power clarified that AURORA was able to select the Jackpot Solar PPA as a cost-effective resource rather than a resource based on capacity or energy need. In the Amended IRP, AURORA selected the Jackpot Solar PPA in the majority of the 24 WECC-optimized portfolios. Because the decision to acquire Jackpot Solar was time bound, Idaho Power agreed with Staff that the Jackpot Solar Action Item should be removed. As Staff noted, however, Idaho Power did not remove this Action Item in the Second Amended IRP.

Idaho Power states that it included this action item in its Amended IRP action plan as it was a significant decision that was based on the results of the 2019 IRP analysis and was part of the action plan in its original IRP filing. Idaho Power notes that it is important to recognize that Jackpot Solar project representatives approached Idaho Power at a unique time during which the company was able to analyze the proposed PPA within the 2019 IRP portfolio development and analysis.

b. Resolution

We understand the recommendation of CUB and Staff is that we not acknowledge action plan item no. 6 because of the Commission's past precedent of not acknowledging action items when they represent actions that the utility has already committed to take or has taken. That precedent comes in part from the Commission's review of PacifiCorp's 2013 IRP, where PacifiCorp included coal plant environmental retrofit investments that were already "substantially complete" in its list of action items for acknowledgment. In declining to acknowledge the investments, the Commission stated "that energy utilities that desire acknowledgment of an investment decision should request acknowledgment before the decision is made and before the required project is substantially completed." The Commission noted it would "review these situations on a case-by-case basis to determine whether or not the project has progressed past a resource planning decision and into a project that is substantially complete."

We also understand Idaho Power to either have agreed that this precedent applies to the Jackpot Solar project in this docket, or to at least not to have strongly objected to applying that precedent.

In this case, we find no compelling reason to depart from our precedent that the parties seem to accept, and decline to acknowledge action item no. 6 for the reasons offered by CUB and Staff. We note that no party took the position that the Jackpot Solar project was problematic in any specific regard, and appreciate the analysis presented by Idaho Power and tested by stakeholders in this case because it has, at least, provided valuable information and transparency into the utility's actions, which will be reviewed for prudence at the time the company seeks cost recovery for the project.

In the future, we continue to reserve our discretion to review utility actions on a case-by-case basis to determine whether they are appropriate for acknowledgment in an IRP process. We recognize that the Commission's past precedent and this case-by-case approach could lead to uncertainty about whether any specific resource decision should be analyzed in an IRP if there is a question about whether the project has reached a level of finality that makes it inappropriate for acknowledgment. We encourage utilities to err on the side of including analyses in their IRPs of resource acquisitions or decisions that will come into service after an IRP is filed, so that such analysis can at least inform parties' and the Commission's views and provide transparency, even if such items are ultimately deemed to not be appropriate for acknowledgment.

2. Boardman Exit by December 31, 2020

In action plan item no. 6, Idaho Power committed to exit the Boardman facility by December 31, 2020. The Boardman closure has been a component of the Company's IRP for several cycles. The Boardman plant retired in 2020, and this resource decision continued to be selected as part of the least cost and least risk portfolio in the 2019 Second Amended IRP. Both CUB and Staff recommended that we not acknowledge this action item because it has already been completed.

We do not acknowledge action plan item no. 6 for reasons similar to those expressed above with regard to the Jackpot solar facility. This action has already occurred, and we do not see a need to reach a decision as to acknowledgment at this stage.

B. Distributed Resources

1. Incorporation of solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP

In action plan item no. 2, Idaho Power will incorporate solar hosting capacity into its customer-owned generation forecast for 2021. Staff notes that this action item is consistent with current Commission objectives and policies associated with Distribution System Planning, which includes guidance that each utility should conduct system evaluations to identify generation in constrained areas.

We acknowledge action plan item no. 2.

2. Monitoring Variable Energy Resource Monitoring (VER) needs, Study of projected effects of addition of Jackpot and early exit of Bridger Units and VER Study

Action plan item no. 5 is to monitor VER variable and system reliability needs and to conduct a study of the projected effects of the addition of Jackpot PV and early exit of Jim Bridger units. Action plan item no. 8 is to conduct a VER study. Both were to be completed by 2020; neither had been completed at the time of the April 15, 2021 Special Public Meeting. Staff agrees that Idaho Power's VER study efforts are appropriate, but that it is not appropriate to acknowledge these action items because they were scheduled for completion in 2020.

Neither of these action items were completed as scheduled, but we understand that Idaho Power still plans to complete them and there were no substantive concerns raised with the VER study that cannot be raised by stakeholders in the ongoing study efforts. Therefore, we acknowledge action plan items no. 5 and no. 8.

3. Energy Efficiency

Idaho Power tested a number of energy efficiency potential forecasting methods in the 2019 IRP, but ultimately adopted a potential study that was the same as the 2017 IRP methodology and served as a base case for comparison purposes. For the 2019 IRP, Idaho Power's outside contractor provided a 20-year forecast of Idaho Power's energy efficiency bounded by the total resource cost (TRC) test. The contractor also provided additional forecasts based on different economic scenarios. The 20-year energy efficiency potential included in the 2019 IRP declined from 273 MW in the 2017 IRP to 234 MW in the 2019 IRP. System on-peak potential from energy efficiency also declined from 483 MW to 367 MW from the 2017 IRP to the 2019 IRP. Idaho Power contends that most of this decline is due to the reduction of available residential lighting measures.

Idaho Power has also indicated that it may be required by its Idaho regulator to use an alternative cost test for energy efficiency in the future.

STOP B2H argues Idaho Power's energy efficiency potential is greater than the company asserts, and that its forecast indicates an insufficient commitment to energy efficiency as a resource.

Staff notes that Idaho Power promised additional energy efficiency studies for the 2019 IRP that were not provided by the company. Staff requests that Idaho Power report on the impact that the Idaho cost evaluation change may have, in conjunction with Idaho Power's obligation to evaluate efficiency potential consistent with Oregon cost assessment methodologies as part of the next IRP. Staff also requests that the company do a comprehensive review of Energy Trust of Oregon's efficiency measures from 2018 through 2020, and share the results.

While contending that its energy efficiency forecasting methodology is consistent with industry standards, Idaho Power agrees to Staff's recommended approach to verifying that its methodology will achieve outcomes with Oregon cost effectiveness methodology and measures evaluated by Energy Trust of Oregon. We adopt Staff's recommendation.

C. Coal Plant Unit Early Exits

1. Valmy Unit 2

Action plan item nos. 9 and 13 are to provide an economic and system reliability analysis on the timing of the exit from Valmy Unit 2 and to exit Valmy Unit 2 by December 31, 2022, respectively. Staff recommends acknowledgment of action item no. 9, but does not recommend acknowledgment of action item no.13. Staff finds there is not currently sufficient analysis of near-term reliability issues to support an earlier date. Staff supports changing the date to the previous exit date at the end of 2025, consistent with economic modeling results in the 2017 IRP.

Idaho Power defends its actions in accelerating the exit date in the action plan to 2022, and requests acknowledgment of this date. The company's initial modeling in the second amended IRP indicates cost savings for customers associated with an early exit date of 2022. Idaho Power is willing to change the date back to the 2025 date, but the company does not wish to ignore the economic modeling results supporting an earlier exit date. Idaho Power must give its ownership partner 15 months' notice of intent to withdraw, so Idaho Power would prefer the acknowledgment of a 2022 exit date at this time. Idaho Power has committed to performing more analysis as soon as possible and will involve stakeholders in a transparent process.

CUB disagrees with Staff's recommendation on action item no.13, and supports acknowledging the 2022 exit date. CUB recommends acknowledgment because the company identified significant economic benefit for customers associated with this 2022 exit timeline in its Second Amended 2019 IRP. CUB notes the accelerated retirement of coal plants is consistent with Oregon's climate goals and climate-associated utility directives. CUB notes Staff's concern that the near-term analysis must be supported by additional cost and reliability analysis. Therefore, CUB's recommendation to acknowledge this item is coupled with an additional recommendation that Idaho Power provide updates to its initial study as soon as possible, given the 15-month notice the company must provide to the plant operator.

Renewable Northwest supports the finding that exiting Valmy Unit 2 in 2022 would provide net economic benefits to Idaho Power and its customers subject to further reliability analysis while recognizing that additional analysis is needed. Renewable Northwest, Idaho Power Conservation League and Sierra Club sent correspondence to the company that presented some additional considerations and modeling adjustments for Idaho Power to use in its subsequent reliability analysis. Renewable Northwest notes that the company was receptive and that the three entities planned to provide additional input to Idaho Power for its future analysis.

Resolution:

We acknowledge action plan item nos. 9 and 13. We are comfortable with Idaho Power's assessment that there are economic benefits for customers associated with the earlier exit date, and agree with CUB that acknowledgment is appropriate for resource decisions supported by long-term portfolio modeling, even if additional analysis may be required to confirm that the utility's decision to proceed with an exit is consistent with near-term reliability considerations. Action item no. 9 is a focused economic and system reliability analysis to further inform the exit date for Valmy Unit 2. We direct Idaho Power to provide the results of the analysis in its 2021 IRP to either confirm the proposed 2022 exit or provide clarification on next steps in the event the early exit is not supported by analysis. We also note that, although an IRP action plan acknowledgment provides important context for utility decision making, the utility retains the responsibility to make the decision that is least cost, least risk and in the best interest of customers, in light of all relevant information at the time of the decision.

2. Exit Jim Bridger Units 1 and 2

Action plan items nos. 1, 7, 10, 11, and 14 all involve coordination with PacifiCorp and evaluation to assess and exit Units 1 and 2 of Jim Bridger. Under the plan, one unit would be retired during 2022 and a second unit retired during 2026. Idaho Power plans to coordinate with PacifiCorp and regulators on the specific timing of the exits.

Staff supports early exit planning from the Jim Bridger Units. Staff notes the need for more coordination between PacifiCorp and Idaho Power. Staff recommends acknowledging four of the five action items relating to the Jim Bridger exits, and further requests to review a reliability impact analysis from Idaho Power. Staff also requested that the company address whether the difference in fixed operation and maintenance (O&M) costs had any significant effect on the selection of the preferred portfolio. Finally, Staff did not recommend acknowledgment of action item no. 7, which is a Regional Haze reassessment of Jim Bridger Units 1 and 2, because the negotiation with Wyoming regulators associated with this item was slated for completion in 2020. These negotiations are now complete in terms of approval from the Wyoming Department of Environmental Quality (DEQ), and now awaits approval from the EPA.

Idaho Power states that its manual adjustment process supported identification of optimal exit scenarios for the Jim Bridger Units through which customers will realize economic benefit. Idaho Power also argues that it appropriately relied on actual fixed O&M costs as the basis for its modeling. Idaho Power concedes that it has not come to terms with PacifiCorp on specific exit dates, but commits to updating the Commission on material developments in negotiations. Idaho Power noted that approval from the EPA is still pending for the Regional Haze reassessment described in action item no. 7.

Renewable Northwest supports the company's exits from Jim Bridger Units 1 and 2 as described in the corresponding action items, and further supports Idaho Power's exits from Jim Bridger Units 3 and 4 by the end of the decade. Sierra Club noted the improved and updated analysis from the company's 2017 IRP. In addition, Sierra Club is concerned that PacifiCorp will attempt to delay Idaho Power's exits from the Jim Bridger units.

Resolution:

We acknowledge action item nos. 1, 10, 11, and 14 supporting early exits from Jim Bridger Units 1 and 2. Idaho Power's analysis demonstrates that customers will realize economic benefits associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026, and the company's exit from the remaining two units at the Jim Bridger facility by the end of the 2020s. Idaho Power views this strategy as consistent with its objectives to ensure low-cost supply. We agree that the early exit due to the favorable economics is reasonable. We will review the additional analysis and updates on negotiation with PacifiCorp in Idaho Power's 2021 IRP.

Jointly owned projects are common in our region as relatively smaller customer bases drive a need to partner in order to realize economies of scale. As we have articulated in other cases, minority partners are expected to vigorously pursue least cost, least risk results for their customers in jointly owned projects. They are expected to stay fully involved in analysis and decision making, evaluating actions independently, and advocating for their customers with their joint owners.[8]

We acknowledge action item no. 7 even though negotiations with the Wyoming DEQ have concluded, because approval from the EPA remains pending. As noted in the Staff Report, more information regarding these exits should be provided in the 2021 IRP, including a reliability impact analysis similar to the one proposed for Valmy.

D. Boardman to Hemmingway (B2H) Transmission Line Action Plan Items

Action plan items nos. 3 and 4 relate to ongoing B2H permitting activities, negotiations with B2H partners, preliminary construction activities, acquiring long-lead materials, and constructing B2H. The B2H transmission project involves permitting, constructing, operating and maintaining a new single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn Station near Boardman, Oregon and the existing Hemingway Substation in southwest Idaho. Idaho Power states that this project will provide the lowest cost, lowest risk capacity resource to meet identified capacity needs commencing in 2026. Idaho Power plans to meet capacity needs through market purchases facilitated by the development of the line.

Proposals for ownership and utilization of the B2H transmission project have changed over time. In the current IRP, Idaho Power proposes ownership of what had previously been the BPA-owned portion of the project. According to current plans, Idaho Power will acquire the BPA ownership share, and BPA would purchase access to B2H through the Company's Open Access Transmission Tariff (OATT). Idaho Power states that PacifiCorp remains financially committed to the project.

[8] See, for example, Docket UE 374, *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Order No. 20-473 at 65 (Dec 18, 2020). There we stated that "Even where PacifiCorp is a minority owner, the company should be prepared to demonstrate in future proceedings the measures it took to actively advocate for its ratepayers' interests and present evidence of meaningful action and analysis."

Party Positions:

Staff recommends acknowledgment of action item nos. 3 and 4 of Idaho Power's Second Amended 2019 IRP relating to the B2H project. Staff supports Idaho Power incorporating cost sensitivities for the B2H project in the 2021 IRP, and supports modeling of B2H cost risk sensitivities in the 2021 IRP. Staff, however, does not support Idaho Power removing or reducing the 20 percent cost contingency. Staff finds incorporating cost contingency is standard practice and a conservative modeling choice that incorporates genuine risk of cost overruns. Staff also supports an update to any B2H costs before creating new portfolios for the 2021 IRP.

Staff also believes B2H is not subject to competitive bidding guidelines, as Order No. 18-324 clarified that "[the] requirements generally do not apply where a utility is seeking to exclusively acquire transmission assets or rights." Staff still believes it is appropriate to consider the potential risk of additional costs for the project as it relates to potential shifts in ownership of the project. Staff recommends additional cost and risk analysis for the B2H project in Idaho Power's 2021 IRP through sensitivity tests for multiple cost futures.

Idaho Power argues that its IRP analysis continues to identify the B2H project as the lowest cost, lowest risk resource option to serve customers. Idaho Power points to extensive modeling and scenario testing that demonstrate that, across a variety of market scenarios, the project remains the lowest cost option. Idaho Power maintains that any shift in ownership will not materially impact the preferred portfolio results in its Second Amended 2019 IRP. Idaho Power states that any ownership changes at this point are hypothetical, and that current partners remain committed to the project. Idaho Power also asserts that, if BPA were to relinquish its ownership share, net costs to customers would not significantly change because it expects BPA would enter into a transmission service agreement with Idaho Power that would offer equivalent cost benefits and risk mitigation to Idaho Power's customers. Idaho Power has agreed that its 2021 IRP will include modeling of the B2H partnership costs and risks.

Idaho Power contends that the B2H project is foundational to a clean energy future for Idaho Power and the western electricity grid, and that it is critical to meeting future carbon reduction goals. Idaho Power disagrees with Staff's recommendation to continue using a 20 percent cost contingency because doing so may functionally duplicate its forthcoming cost sensitivity analysis, and Idaho Power is currently working to update cost estimates.

STOP B2H argues that the B2H project should not be acknowledged and that the central premise of the project, that it can deliver lower cost energy from Mid-C, has not been sufficiently tested. STOP B2H recommends Idaho Power complete a more robust market analysis, including markets beyond the Mid-C, for potentially advantageous alternatives to meeting its capacity needs. STOP B2H references an IPUC determination that found that the Jackpot Solar project was cheaper than Mid-C market purchases, and therefore that the project would provide Idaho Power's customers with less expensive, clean renewable energy than Mid-C market purchases over a 20-year period. According to STOP B2H, this supports non-acknowledgment as evidence that alternative resources may provide more cost-effective energy than the B2H project. STOP B2H also believes that, in Idaho Power's 2017 IRP, we acknowledged only Idaho Power's 21 percent of a 2,050 MW bi-directional transmission line, and requests that we affirm this understanding of the limited nature of our previous acknowledgment.

Idaho Power refutes the STOP B2H claim that market purchases are over-priced relative to new renewable energy like Jackpot Solar. Idaho Power agrees the Jackpot Solar resource is cost-effective, which is why Idaho Power executed a PPA to purchase the project's output. But Idaho Power believes STOP B2H is misguided in its implication that Mid-C has a static (and high-cost) price relative to Jackpot Solar or other resources. Idaho Power argues that Mid-C is a dynamic market where prices go up and down based on supply and demand. As such, Mid-C is not a single resource and should not be used to support the incorrect inference that B2H is a more costly resource than solar. Rather, B2H provides a different value to Idaho Power's customers in the form of a firm and diverse resource—for instance, by providing access to power in those hours when Idaho Power has a capacity need when a solar facility may not operate.

STOP B2H also argues that without firm terms for the Bridger exits with PacifiCorp, exit dates are actually undefined and do not support the need for B2H. Idaho Power notes that the second Bridger unit retirement date of 2026 will result in a resource deficiency and is not possible without the addition of other resources. Idaho Power argues the most efficient way to address this deficiency is with the B2H project.

CUB supports Staff's recommendation for the Commission to acknowledge action items 3 and 4 addressing permitting, construction, and long lead material acquisition for the B2H transmission line. CUB joins Staff in recommending additional cost and risk analysis for the B2H project in Idaho Power's 2021 IRP through sensitivity tests for multiple cost futures. CUB supports Staff's additional recommendation to have Idaho Power continue to include the 20 percent cost contingency for the B2H project in the 2021 IRP.

STOP B2H argues that the degree of uncertainty with B2H costs should require a contingency assumption greater than the 20 percent contemplated. Renewable Northwest supports acknowledgment of the B2H project as a resource that will provide low-cost, low-carbon energy and capacity to the company.

Numerous comments detail the impacts the project will have on the landscape and communities along the route, and state that lower-cost alternatives are available. Some comments note that a supply option, like the B2H project, will create impacts on the land and its residents for generations, while other options, like solar energy resources, will not. For this reason, the commenters argue, Idaho Power should embrace those lower-impact resources. Other comments note that Idaho Power's stated need for additional capacity and energy has consistently fallen throughout the consideration of the project. Comments also generally oppose the project because of the impact it is anticipated to have on cultural resources, natural resources and wildlife. Finally, comments note that in recent years transmission lines have been identified as the origin of wildfires in California, and that this negative impact has not been taken sufficiently into account in consideration of the project.

Resolution:

We acknowledge action items nos. 3 and 4, regarding the Boardman to Hemingway (B2H) project. By doing so, we find that these action items related to B2H are reasonable at this time and for this IRP, given the information developed through our IRP processes. We agree with Staff that a cost contingency for the project is necessary, and that developing an appropriate contingency is an important and standard part of consideration of a resource of this character. In response to comments for clarification from STOP B2H, we will allow the 2017 IRP Order to speak for itself. We affirm here that we acknowledge the B2H project action items in this IRP, which are applicable to the proposed project as it is presented in the company's Second Amended 2019 IRP, which includes a 500 kV transmission line with the partnership arrangement as described by Idaho Power.

In coming to this conclusion, we have reviewed Idaho Power's Second Amended 2019 IRP and Staff's analysis and recommendations, the filed comments of all stakeholders, and all of the comments submitted by individual commenters. We have also engaged with stakeholders and the public during public meetings and workshops and consider these inputs fully and carefully in our decision-making process. We have received many comments from members of the public, and we very much appreciate the time and effort required to engage with our processes.

Many commenters lament the impacts that this project is expected to create on the landscape and to their communities. We take these comments seriously, and they help inform us about the risks and impacts of the proposed project. Ultimately, we make a determination on the reasonableness of Idaho Power's plan to serve customers with the B2H project; we do not review or expressly weigh the impacts to communities that this project or resource selections broadly may present, as opposed to the land and community impacts of other options for serving customers. We have considered, and will continue to consider the risks of the project described by public commenters that are relevant to our least-cost, least-risk review standards, and we consider the opposition to the line as relevant to informing us about the risks of cost overruns, or potential barriers that Idaho Power may face in seeking to construct the project. For all proposed resource solutions, however, the direct consideration of questions regarding local impacts are addressed in forums other than our IRP process.

Our acknowledgment means that the action plan items pertaining to this project, as currently presented, meet our guidelines of least-cost, least-risk planning for customers. We emphasize it is not a determination of the prudency of the overall project, nor are we granting Idaho Power cost recovery for any portion of the B2H project as proposed at this time. A prudency review and ratemaking decisions will occur in future proceedings, at such times as those determinations are required. As described by Idaho Power in its Second Amended 2019 IRP, the activities and actions that move the B2H project forward will continue to require ongoing analysis in future IRPs and other proceedings. Those future proceedings can and will involve continued review and analysis of the B2H project, and will continue to test the assumptions and projections that justify the proposed actions.

We note that, in general, the analysis presented supports the project. The project is reasonably modeled, meaning that core assumptions underlying the analysis such as projected market prices, capacity needs, and resource costs have been tested by stakeholders and fall within a reasonable range. In multiple scenarios, the B2H project remains cost-competitive, even in scenarios where fundamentals not favorable to the project are tested, such as where the cost contingency is triggered and under a variety wholesale energy cost estimates. Throughout these scenarios, Idaho Power has demonstrated that the project is reasonable, and given the information available today, the projected least-cost, least-risk option.

We recognize the scale of this project and understand the potential impacts to Oregon, including the communities and lands that will be most impacted by the project. We recognize the uncertainties surrounding this project, including cost, cost risks, partnerships, and market depth. We also recognize that these risks and uncertainties must be evaluated in a context of potentially significant opportunities and benefits, including enabling better regional integration of low-cost renewables, allowing clean energy goals to be met at a lower cost to consumers, advancing regional reliability, and avoiding the need to meet large-scale capacity needs with new fossil fuel infrastructure that is at risk of being economically stranded.

We find that Idaho Power's analysis of the project in its IRP comports with our established guidelines and is reasonable, even though we recognize there are still questions to be answered and that future developments, yet to occur, will continue to be reviewed. Below, we review these issues and emphasize at the conclusion of this resolution that we expect the company to produce updated and ongoing analysis to address these issues in the 2021 IRP.

First, cost overruns are a matter of significant concern, as they often are with large, complex resource solutions. Idaho Power must continue to stress test this project aggressively as a part of the preferred portfolio. Idaho Power's stress testing must build in potential costs and cost contingencies that arise with concerns on the landscape, wildfire, and property risks. Typically, construction cost contingencies narrow as the project reaches completion. However, given the substantial size of this project, Idaho Power must keep the range of cost uncertainty reasonably wide in its modeling exercises and contingency planning. We agree with Staff that Idaho Power's cost contingency should not be removed. We agree that incorporating a reasonable cost contingency is standard practice that helps prepare for the risk of cost overruns, and is valuable during the modeling process. We decline to determine that 20 percent is the appropriate cost contingency, but expect Idaho Power to explain and support the cost contingency assigned to this project in the 2021 IRP.

Second, the specific partnership structure of the project remains unresolved. Idaho Power states that BPA remains committed to the project and that its 21 percent share of the project is still appropriate. The company further states that it will not shift additional costs to retail customers without an increased and corresponding benefit for those customers. Idaho Power states that ownership details will be finalized and presented in its 2021 IRP. Partnerships are vital to the project's future success and will need to be closely monitored. Partnership agreements bring complexity to the project and Idaho Power must continue to evaluate the risks to customers that result from these arrangements. We expect Idaho Power to analyze closely whether expanding its ownership share from 21 percent, and relying on OATT revenues to offset its additional costs is truly comparable, in terms of risks and financial impacts, to joint ownership. Where differences may exist, we expect that Idaho Power will explain how those risks are mitigated or considered in its analyses.

Stakeholders have questioned the availability of market resources over the long term, particularly given regional resource adequacy needs. We note that Idaho Power's market needs are centered in the early summer months, driven by irrigation use, which is distinguishable from the broader current resource adequacy needs in the region, and supports the conclusion that market resources will be available to meet Idaho Power's needs, based on the best information available today. Idaho Power's modeling has also consistently demonstrated that it saves money to retire coal and replace it with a blend of renewables and transmission that connects customers to markets and brings low-cost economics to the table. Nonetheless, as market conditions and availability are central to the success of this project as a resource, they must continue to be reviewed and tested.

In addition to market dynamics, project costs must be consistently updated as Idaho Power moves forward with this project. STOP B2H recommends, and Staff agrees, that Idaho Power should update its estimated costs prior to submitting its 2021 IRP. Idaho Power states that it plans to update its estimated project costs in the next IRP and has hired a consultant to assist.

We would specifically like to see cost updates explicitly account for design changes for operating the line in a mid-century climate, particularly accounting for the changing understanding of wildfire risks by mid-century. We plan to continue to analyze new information regarding this wildfire issue as it becomes available, and expect the uncertainties surrounding this and other risks to be resolved as the company continues its own evaluation, development and refinement of applicable action plan items. These issues, and the many estimates, details, and analyses will continue to be monitored and evaluated in the next IRP, which the company states will be filed no later than the end of this year.

We note that our acknowledgment is limited to our interpretation of IRP standards specific to the Oregon Public Utility Commission and does not interpret or apply the standard of any other state or federal agency.

E. Additional Recommendations

1. Renewable Northwest – Renewables plus Storage

Renewable Northwest requests that Idaho Power model renewables plus storage as part of IRP planning. Idaho Power has agreed to do so for the next IRP. We appreciate the efforts of Renewable Northwest to raise this issue, and expect this to be addressed in Idaho Power's 2021 IRP.

2. Demand Response

Idaho Power's original 2019 IRP action plan included acquisition of 5 MW of Demand Response (DR) in 2026. After discovering that its IRP modeling only dispatched DR in resource deficit situations, Idaho Power revised modeling to treat DR as a resource to offset load, which resulted in additional DR being selected in the preferred portfolio.

CUB expressed concern over both the scope of Idaho Power's DR review, which CUB found inadequate given the DR opportunities exploited by utilities across the country, and by the delay in the acquisition of DR in the plan. CUB notes that DR acquisition is a multi-part, multi-year strategy and must be ramped up over time. STOP B2H notes that the Northwest Power and Conservation Council in its 7th Power Plan has determined that DR is the cheapest way to meet capacity needs, and must be prioritized as a result.

Idaho Power argues that it has embraced DR as much as practicable, and that it executed a settlement agreement in 2013 that bound Idaho Power not to add new DR programs in years when it did not anticipate peak-hour capacity deficits. Staff is concerned that levelized cost of capacity (LCOC) of the DR modeled by the Idaho Power is inadequate, and requests that the 2021 IRP should model expanded DR with an LCOC based on programmatic approximations for acquiring incremental DR.

Resolution:

We acknowledge Idaho Power's DR acquisition plan, and adopt Staff's recommendation. As discussed above, in the context of Idaho Power's resource acquisition efforts, DR needs comprehensive review. We agree with CUB that programs need to be expanded in general, and conceived of and developed earlier in time. DR needs to be a priority for Idaho Power, and it needs to carefully review how DR could fill out peak needs, with potentially lower costs than alternative resources.

3. Error Testing of the Load Forecast

Staff recommends that Idaho Power be required to present a plan for cross-validation to check whether Autoregressive Integrated Moving Average (ARIMA) modeling is likely to reduce load forecast error. Idaho Power argues that other modeling options may be superior and should be reviewed, and that ARIMA has been shown to produce highly accurate short term forecasts, but that for IRP purposes, the longer-term forecasts are the priority in the analysis.

We do not adopt Staff's recommendation to require that Idaho Power replace its error testing methodology for the load forecast with ARIMA. Instead, we determine that Staff should work with Idaho Power to review the current framework and alternatives, and that Idaho Power should work with Staff and stakeholders to update its methodology. After working with stakeholders, Idaho Power should be prepared to justify its final chosen approach in its next IRP.

4. Renewable Energy Coalition – Wind Sensitivity Analysis and QF Capacity Value.

The Renewable Energy Coalition (REC) highlighted two Qualifying Facility (QF) related issues for our consideration. First, REC and Staff identified issues associated with wind QF renewal estimates in the Idaho Power IRP. Next, REC reviewed the value of capacity provided by QFs in avoided costs.

In its 2019 Second Amended IRP, Idaho Power assumes no QF wind contracts will renew. In its final April 6, 2021 Report, Staff noted that there is risk in assuming none of these wind contracts will renew, and recommended that, as a part of its 2021 IRP, the company perform a sensitivity analysis pertaining to wind replacement assumptions, in order to evaluate the impact on resource planning.

In response to the Staff Report, REC supported Staff's recommendation for a sensitivity analysis, but noted that Idaho Power should be directed to do more. REC notes that the company continues to forecast all of its wind resources continuing while not including any QF wind resources. REC recommends that Idaho Power be directed to provide a more detailed explanation in future IRPs to better aid stakeholder understanding of this discrepancy.

The second issue raised by REC is the value of the capacity provided by QFs included for renewal in the company's IRP. REC argues the capacity value associated with these renewals are not adequately reflected in avoided costs. Staff states in its Report that the issue is "out of place" in this docket, and will be addressed in our general investigation into avoided cost methodology in the UM 2000 docket. Idaho Power noted that its first wind QF contracts will not be eligible for renewal until 2027. The company asserted that, because it has no experience with wind QF renewals from which to draw upon, its analysis assumes no QF wind contract renewals.

Resolution:

Wind renewals are still several years away, but we agree with Staff that modeling should include some percentage, rather than taking an "all or nothing" approach. Idaho Power's assumption of zero renewals of wind QFs is unrealistic, but assuming that all resources will renew may also not be realistic. Some reasonable assumption must be made. Without any actual experience, developing such an estimate may seem arbitrary, but IRPs are, in part, based on such uncertainties and reasonable estimates and forecasts. In addition to adopting Staff's recommendation to come up with reasonable assumptions through a sensitivity analysis, we direct that, in the next IRP, Idaho Power explain how the sensitivities resulting from the study would affect the IRP's preferred portfolio and action plan if incorporated. Although we prefer that this issue be addressed generically, through UM 2038, we recognize that this docket has been delayed and conclude that such delay should not preclude directing utilities to advance toward more reasonable renewal assumptions in individual IRPs.

Regarding compensating QFs for capacity value, we agree with Staff that IRP acknowledgment decisions should not directly address avoided cost methodology nor make avoided cost pricing determinations. Capacity valuation and its impact on PURPA avoided cost methodology will be addressed in other Commission dockets, including but not limited to UM 2000 and UM 2011.

IV. ORDER

IT IS ORDERED that:

The Integrated Resource Plan filed by Idaho Power is acknowledged as described with the terms of this order and the attached Appendix A.

Made, entered, and effective Jun 04 2021.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

THE UNION

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: April 6, 2021

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __**Upon Commission's Approval**__

DATE: March 5, 2021

TO: Public Utility Commission

FROM: Nadine Hanhan

THROUGH: Bryan Conway, JP Batmale, and Kim Herb **SIGNED**

SUBJECT: IDAHO POWER COMPANY:
(Docket No. LC 74)
Acknowledgement of the 2019 Integrated Resource Plan.

STAFF RECOMMENDATION:

Acknowledge Idaho Power's 2019 Integrated Resource Plan (IRP) in part and decline to acknowledge in part Idaho Power's 2019 Integrated Resource Action Plan. Staff recommends certain action and additional requirements on pages 52-56 of this Staff Report.

SUMMARY OF STAFF RECOMMENDED ACTIONS:

Commission Staff ("Staff") presents a summary of recommendations on each Action Item, in the order presented in the Action Plan. Due to the extended cycle of this IRP, many of these Action Items have already been completed, and as a result, Staff recommends not acknowledging them. In Order No. 14-252, the Commission noted that energy utilities that desire acknowledgment of an investment decision should request acknowledgment before the required project is substantially completed. As a result, Staff recommends not acknowledging Action Items based on procedural grounds when they are complete or will be substantially complete by the time the Commission issues its acknowledgment order. Such recommendations do not necessarily indicate lack of support for the Action Items. Because Staff is recommending a waiver for the 2019 IRP Update, all recommendations are for the 2021 IRP unless stated otherwise. Dates in parentheses are taken from the Action Plan target year.

1. Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition. (2020-2022)
   Recommendation: Acknowledge

   Additional Recommendation: Provide a reliability impact analysis for Jim Bridger retirement.

2. Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP. (2020-2022)
   Recommendation: Acknowledge

3. Conduct ongoing Boardman to Hemingway (B2H) permitting activities. Negotiate and execute B2H partner construction agreement(s). (2020-2026)
   Recommendation: Acknowledge

4. Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. (2020-2026)
   Recommendation: Acknowledge

   Additional Recommendations:
   - Continue to include the 20 percent cost contingency for B2H in the 2021 IRP.
   - Update B2H costs prior to creating new portfolios in the 2021 IRP.
   - Model cost risk as it relates to a change in ownership arrangement in the 2021 cycle. This could be in the form of a series of sensitivities, where the Company continues to own 21 percent of the line and retail customers are held harmless, and introduce additional costs to customers based on a range of capital risks.
   - Dedicate time in a 2021 IRPAC meeting addressing the issue of B2H cost risk as a result of new ownership structures. In the meeting, the Company should address the questions raised in this Staff Report.

5. Monitor Variable Energy Resource (VER) variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units. (2020)
   Recommendation: Not Acknowledge due to timing

   Additional Recommendation: File the results of each of the VER studies with the Commission once they are complete and notify the LC 74 service list.

6. Exit Boardman December 31, 2020. (2020)
   Recommendation: Not Acknowledge due to timing

7. Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized. (2020)
   Recommendation: Not Acknowledge due to timing

   Additional Recommendation: Update the Commission as soon as it knows the outcome of PacifiCorp's negotiation with the Wyoming DEQ regarding continued use of Jim Bridger Units 1 and 2 without SCR investments.

8. Conduct a VER Integration Study. (2020)
   Recommendation: Not Acknowledge due to timing

9. Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2. (2020-2021)
   Recommendation: Acknowledge

10. Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units. (2021-2022)
    Recommendation: Acknowledge

11. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022. (2022)
    Recommendation: Acknowledge

12. Jackpot Solar 120 MW on-line December 2022. (2022)
    Recommendation: Not Acknowledge

13. Exit Valmy Unit 2 by December 31, 2022.
    Recommendation: Not Acknowledge

    Additional Recommendation: Change the Action Item to include a Valmy Retirement in 2025 until the Company has completed the appropriate analysis to show 2022 is an optimal retirement date.

14. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H). (2026)
    Recommendation: Acknowledge

Following is a list of additional Staff Recommendations based on analysis in this Staff Report.

Additional Staff Recommendations

- Report qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.
- Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.
- Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.
- Review all energy efficiency measures piloted by Energy Trust in 2018-2020 and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. The Company should share the status of its review at an Energy Efficiency Advisory Group meeting in 2021 and as a report in the 2021 IRP.
- Use a metric like the Akaike Information Criterion to confirm that indicator variables are not causing model overfitting.
- Present a plan for cross-validation or similar to check whether ARIMA models are likely to reduce load forecast error in the next IRP and check robustness of Idaho Power's load forecasting model.
- Address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.
- Present to Commissioners the impact of COVID-19 on load.
- The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.
- Provide an update on the Oregon Residential Time-of-Day Pilot Plan including number of participants, total cost of the pilot since its 2019 launch, and peak

capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the Smart Grid Report will be suspended with the Commission approval of DSP guidelines.

- Work with Staff and stakeholders to develop a new modeling approach suitable for behavior-based DR programs that reflects such programs' typical lower costs and less certain results.
- Perform sensitivity analysis in its 2021 IRP pertaining to wind replacement assumptions to evaluate the impact on resource planning.
- Allow an exemption to Order No. 16-362.
- Perform the Company's approved capacity factor approximation method using all the new data that has become available.
- Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.
- Model the PTC for wind to the extent it is technically achievable by the Company.
- Revise its Wyoming cost inputs to include more reasonable cost assumptions.
- The Company should produce the Climate Change Risk Report referenced in the 2017 IRP acknowledgment order and include it in the next IRP.
- Waive the IRP Update unless the Company is unable to file its IRP before the annual update deadline.

DISCUSSION:

<u>Issue</u>

Whether the Commission should acknowledge Idaho Power Company's ("Idaho Power" or "the Company") 2019 Integrated Resource Plan (IRP), acknowledge specific portions of the IRP with or without certain conditions, or decline to acknowledge the IRP.

<u>Applicable Rule</u>

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), 08-339, and 12-013 clarify the procedural steps and substantive analysis required

[1] Order No. 89-507.

of Oregon's regulated utilities in order for the Commission to consider acknowledgement of a utility's resource plan.[2] Also applicable to review of Idaho Power's 2019 IRP is whether it complies with all of the Commission requirements in its previously acknowledged IRP. In addition to IRP Guideline compliance, Staff reviewed whether Idaho Power complied with the Commission's order in LC 68.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The ultimate goal of the IRP is to select the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonable based on the information available at the time.[6] However, the Commission also explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7] The Commission may also decline to acknowledge specific Action Items if they are complete or substantially complete by the time the Commission issues its acknowledgment order.[8]

Analysis

Procedural History

Prior to the initial IRP filing on June 28, 2019, Idaho Power held eight IRP Advisory Council (IRPAC) meetings leading up to the submission of the initial 2019 IRP and two more IRPAC meetings for the *Second Amended* IRP. IRPAC members represent various public agencies, public and private enterprises, and advocacy groups. The IRPAC covers aspects of the IRP development, particularly on the resource stack,

[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: *See* Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] Order No. 07-002 at 1.
[7] Order No. 07-002 at 1.
[8] Order No. 14-252 at 7.

resource portfolio considerations, and risk analyses. The IRPAC played an integral role, and Staff appreciated the involved stakeholder process and Idaho Power's time and energy in fulfilling the public input component of the Company's IRP process.

Idaho Power filed its initial 2019 IRP on June 28, 2019. The Company's filing included the IRP and four appendices.[9] Several weeks later, the Company filed a letter asking the Administrative Law Judge to refrain from establishing a procedural schedule to allow the Company to file supplemental analysis related to the Company's Long Term Capacity Expansion (LTCE) modeling approach to confirm the accuracy of the IRP's conclusions and findings. The LTCE is new to this IRP cycle, and this is the first time the Company has incorporated this methodology in the IRP.

On January 31, 2020, the Company filed an *Amended* IRP that included multiple changes to its analysis and some changes to the Company's preferred portfolio. On June 1, 2020, Idaho Power amended its IRP again by submitting replacement pages meant to address truncated Bridger coal cost errors it discovered after filing the *Amended* IRP. On July 1, 2020, the Company filed a motion to suspend the schedule because it discovered additional errors and felt the need to do a comprehensive review to ensure accuracy in the IRP. On October 2, 2020, the Company filed its fourth iteration of the IRP, the *Second Amended* 2019 IRP, to correct input errors. The Company underwent an extensive verification process in this final version.

The Commission held a virtual public comment hearing on April 23, 2020, and hosted two additional workshops on October 22, 2020 and March 2, 2021.

On April 1, 2020, Staff filed Opening Comments on the Company's *Amended* IRP. On April 2, 2020, Mr. Gail Carbiener, the Citizens' Utility Board ("CUB"), the Renewable Energy Coalition ("REC"), Renewable Northwest, ("RNW"), Sierra Club, and the STOP B2H Coalition ("STOP B2H") filed Opening Comments. On April 7, 2020, STOP B2H filed revised and amended Opening Comments.

On May 15, 2020, the Company filed Reply Comments. As mentioned above, the docket schedule was suspended, and the Company subsequently filed its final iteration of the IRP on October 2, 2020.

On January 8, 2021, REC, Staff, CUB, RNW, and STOP B2H filed Final Comments.

On February 5, 2021, Idaho Power filed Final Comments.

[9] The appendices are the "Sales and Load Forecast," the "Demand-Side Management 2018 Annual Report," the "Technical Appendix," and the "Boardman to Hemingway Update."

Staff also received a number of informal comments throughout the proceeding. Almost all of the informal comments Staff reviewed opposed the construction of the B2H line, but one commenter expressed support for retirement of Valmy Unit 2, and another supported moving away from coal and gas and moving towards renewable sources of energy.

This Staff Report discusses the near-term Action Plan, formal comments by stakeholders and the Company, and other issues raised throughout this docket. Due to the multiple iterations of the IRP, the Staff Report will focus on the *Second Amended* IRP unless stated otherwise. Staff organizes this report by first discussing the Action Items in the Action Plan, followed by additional issues raised by parties.

Action Item Discussion

Below is a summary of Idaho Power's Action Plan Items in the 2019 Second Amended IRP.

Summary of Idaho Power 2019 Action Plan Items by Category	
Category	**Final 2019 Action Plan Item**
Jim Bridger Early Exits	- 1: Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units.
	- 10: Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
	- 11: Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.
	- 14: Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit is tied to the need for a resource addition (B2H).
Customer Solar	- 2: Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
B2H	- 3: Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s). - 4: Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
VER Monitoring	- 5: Monitor Variable Energy Resource (VER) variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units. - 8: Conduct a VER Integration Study.
Boardman Exit	- 6: Exit Boardman December 31, 2020.
Regional Haze	- 7: Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.

Valmy Unit 2 Exit	- 9: Economic and system reliability analysis on timing of exit from Valmy Unit 2. - 13:Exit Valmy Unity 2 by December 31, 2022.
Jackpot Solar	- 12: Jackpot Solar 120 MW on-line December 2022.

Jim Bridger Early Exits

Action Items 1, 10, 11, and 14 regard early exits from Jim Bridger units. Target dates for early exits involve retiring one unit during 2022 and a second unit during 2026. The Company seeks to coordinate with PacifiCorp and regulators on the timing of these early exits.

Idaho Power's Analysis

The Jim Bridger coal plant contributes substantially to Idaho Power's generating capacity, and the retirement dates of the Jim Bridger units are important drivers of resource selections in the IRP. Through Idaho Power's new Long Term Capacity Expansion (LTCE) methodology, the Company's preferred portfolio identified 2022 and 2026 for retiring Units 1 and 2 of the Jim Bridger coal plant, though the exit order of these units has not been identified. Idaho Power is also planning on retiring units 3 and 4 in 2028 and 2030, with the order also unspecified.[10]

Stakeholder Positions

Sierra Club

Sierra Club indicated that the analysis behind Idaho Power's 2019 IRP was a "dramatic improvement" from the 2017 IRP.[11] It was generally supportive of Idaho Power's new LTCE approach and early retirement dates, though it was concerned that Idaho Power's partner, PacifiCorp would delay early retirement. Sierra Club discussed at length economic merits of early unit retirement and disputed the assertion that the Jim Bridger power plant plays a valuable role in balancing variable renewable resources or providing flexible capacity.

CUB

CUB noted that the Jim Bridger exit dates for Unit 1 and Unit 2 in PacifiCorp's Action Plan (2023 and 2028) were different from the exit dates in Idaho Power's Action Plan (2022 and 2026). While CUB believes that removing coal-fired generation from the resource portfolio is vital to a transition towards Idaho Power's goal of 100 percent

[10] Idaho Power *Second Amended* IRP, page 18.
[11] LC 74, Sierra Club Opening Comments, page 1.

Clean Energy by 2045, CUB stated that the Company needed to provide clearer plans regarding coal exits.[12]

RNW
RNW expressed its appreciation that Idaho Power is seeking to economically retire five of seven coal-fired generating units by the end of 2026 and exit from the remaining two at Jim Bridger by the end of the 2020s.[13]

Staff's Positon
Staff noted that the Company did not specify which dates each unit would be retiring.

Staff looked into Idaho Power's fuel cost and fixed cost forecasts for Jim Bridger, Idaho Power's coal fuel price forecast, and compared it to the one used in PacifiCorp's 2019 IRP. In PacifiCorp's IRP, Staff and Sierra Club expressed concern with the coal fuel cost forecast for Jim Bridger, which appeared to be unreasonably low. Staff found that Idaho Power's coal fuel price forecast did not provide the same cause for concern.

Staff also reviewed the fixed O&M costs of the Bridger units and found that the fixed costs for PacifiCorp's share of the plant differed from Idaho Power's share of the plant. It is Staff's understanding that Idaho Power developed the fixed costs for Idaho Power's share of the plant, whereas a vendor developed the fixed costs for PacifiCorp's share. Staff requested that Idaho Power review its cost assumptions for both companies' shares of the plant and explain the cause and significance of the difference in fixed O&M between these two shares of the plant. Staff requested that the Company address whether the difference in fixed O&M costs had any significant effect on the selection of the Preferred Portfolio.

Idaho Power's Position
Idaho Power indicated that though it has not decided which units would retire in what year, Units 1 and 2 would be likely to retire in 2022 and 2026 due to their relative condition, efficiency, and outage schedules.[14] At the time of the Company's Reply Comments, it explained that it had only had high-level discussions with PacifiCorp about retiring Jim Bridger units in tandem.[15] It stated that because these discussions were still beginning, it is difficult to plan towards resolution of the different retirement dates. However, it was amenable to update the Commission on negotiations with PacifiCorp at the end of 2020.[16]

---

[12] LC 74, CUB Opening Comments, page 8.
[13] LC 74, RNW Opening Comments, page 7.
[14] These units are also unspecified.
[15] LC 74, Idaho Power Reply Comments, page 38.
[16] This statement was made on page 38 of its Reply Comments, before the Company had suspended its Amended IRP.

In Final Comments, Idaho Power explained that it generally does not alter model vendor inputs for other companies' units because other companies might have differing O&M costs, capital upgrade methodologies, or regulatory environments. The Company also provided a brief update regarding negotiations among parties, stating that PacifiCorp and Idaho Power have not yet come to terms on exit dates. Idaho Power committed to updating the Commission with substantive developments.

Staff's Analysis and Recommendation:

In the 2017 IRP, the Commission did not acknowledge the retirement dates proposed for the Jim Bridger units: 2028 for Unit 2 and 2032 for Unit 1. Staff had recommended not acknowledging the retirement dates because it believed that the Company had not established that its plan to retire the Bridger units in those years in lieu of installing SCRs in 2021 and 2022 was feasible. In the 2019 IRP, Staff has reviewed costs and believes that an early economic retirement would be reasonable, but Staff also shares Sierra Club's concern about consistency between the Company and PacifiCorp. Idaho Power has yet to demonstrate comparable cost assumptions for both operating partners as well as a secure plan for early retirement coordination.

Idaho Power should strive with PacifiCorp to share data to ensure that the appropriate information is captured properly in the IRP. Further, 2022 is swiftly approaching. The Company has not yet provided material updates on which unit will retire or whether it will be able to secure negotiations with PacifiCorp to retire in 2022. Staff would also be interested in a reliability impact analysis similar to the one proposed for Valmy in the form of a filing or update from the Company.

Staff Recommendations:

- **Acknowledge Action Item 1: Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units.**
- **Acknowledge Action Item 10: Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.**
- **Acknowledge Action Item 11: Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.**
- **Acknowledge Action Item 14: Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit is tied to the need for a resource addition (B2H).**

Recommendation for 2021 IRP:

- **Provide a reliability impact analysis for Jim Bridger retirement.**

Customer Solar

Action Item 2 is to incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.

Idaho Power's Analysis

As of March 31, 2019, the Company's total solar customer-generation capacity was 36.302 MW in Idaho and 1.267 MW in Oregon.[17] The Company states that it will incorporate solar hosting capacity into its customer-owned generation forecasts in the 2021 IRP.

Staff's Position

No parties submitted comments on this Action Item. Staff supports this Action Item as it is consistent with current objectives and policies at the Commission regarding Distribution System Planning. For example, Staff's proposed guidelines in UM 2005 include Hosting Capacity Analysis guidance that each utility should conduct system evaluations to identify generation in constrained areas.[18]

Staff Recommendation:

- **Acknowledge Action Item 2: Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.**

Boardman to Hemingway (B2H)

Action Items 3 and 4 regard ongoing B2H permitting activities, negotiations with B2H partners, preliminary construction activities, acquiring long-lead materials, and constructing B2H.

[17] Idaho Power 2019 *Second Amended* IRP, page 41. This includes pending and active capacity.
[18] UM 2005 Staff Report, Attachment 1 page 7.

Idaho Power's Analysis

The B2H project is a planned 500-kilovolt (kV) transmission project that would run between the Hemingway 500-kV substation near Marsing, Idaho, and a proposed substation near Boardman, Oregon.[19] The project has consistently been selected as part of the Company's preferred portfolio for over a decade, and the 2019 cycle is no different. The Company maintains that B2H provides the least-cost option for its resource future, in addition to incremental ancillary benefits and additional operational flexibility.[20]

The 2019 *Second Amended* IRP portfolio selection process included a new methodology that created portfolios with and without B2H so that Idaho Power could compare the costs of a resource future with and without the transmission line. Ultimately, with this new process, the Company again determined that B2H should be part of a least-cost/least-risk portfolio.

A significant change in the *Second Amended* IRP included an informational update that Idaho Power is considering acquiring Bonneville Power Administration's (BPA) 24 percent ownership share of B2H.[21] To Staff's knowledge, the Company did not incorporate this change into the IRP's cost assumptions.

Stakeholder Positions

STOP B2H

STOP B2H's comments strongly opposed construction of B2H. Because the *Second Amended* IRP contained updates to portfolio costs, new assumptions and methodologies, and created new portfolios, parts of STOP B2H's analysis in Opening Comments do not apply to the *Second Amended* IRP.[22] The inapplicability of the comments mostly revolve around outdated cost assumptions.

However, STOP B2H also presented a series of concerns on the *Amended* IRP that Staff believes could still be considered applicable in the *Second Amended* IRP. These critiques include, but were not limited to:

- Real power losses due to the transport of power across long distances,
- Excess Capacity Benefit Margin (CBM) assumptions in the IRP,

[19] Idaho Power 2019 *Second Amended* IRP Appendix D, page 1.
[20] Idaho Power 2019 *Second Amended* IRP Appendix D, page 1.
[21] Idaho Power 2019 *Second Amended* IRP, page 19.
[22] This also applies to other parties' analysis on the portfolios in previous iterations of the IRP.

- Its dispute that Idaho Power has met the standards under the Energy Facilities Siting Council (EFSC) System Reliability Rule,
- The belief that B2H falls under the Commission's competitive bidding rules, and
- Risks around project participants.

In Final Comments on Idaho Power's *Second Amended* IRP, STOP B2H continued to focus on project participant risk.[23] The group indicated that project participants have been inconsistent in their commitment to B2H. STOP B2H also expressed concern about potential cost overruns of the project and requested that the Company reflect any cost changes in the 2021 IRP.

Mr. Gail Carbiener
Mr. Gail Carbiener filed Opening Comments opposing construction of B2H. Mr. Carbiener also focused on co-participant risk and indicated that he was surprised at the lack of coordination between PacifiCorp and Idaho Power on construction of the line.[24]

CUB
CUB had concerns with co-participant risk in its Opening Comments, including the risk that if PacifiCorp or BPA were to pull out of the project, there would either be cost allocation impacts on Idaho Power's customers, or the project could be deferred. Despite these concerns, CUB makes no recommendations on B2H.

Renewable Northwest
In general, Renewable Northwest supported construction of B2H because it agreed with Idaho Power on several points, namely that that B2H will "provid[e] Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market," improve system reliability and resiliency, reduce limitations on the regional transmission system, and that the Company "persuasively tied its transmission proposal" to its 100 percent clean goal.[25]

<u>Staff's Position</u>
Staff agreed with the issue of cost risk related to ownership changes and recommended that for the 2021 IRP, the Company must measure cost risk as it relates to changes in ownership of B2H. At the time Staff filed Opening Comments, the Company was still representing that the three original parties would continue to own a share of the line. Staff expressed concern about the possibility of one party stepping away from the project and highlighted the cost risk it could pose for ratepayers.

---

[23] STOP B2H Final Comments, page 7.
[24] Gail Carbiener's Opening Comments, pages 1-2.
[25] RNW Opening Comments, pages 4-5.

By the time Staff filed Final Comments, parties learned that B2H ownership would potentially be restructured. Idaho Power proposed that it could acquire BPA's ownership share. BPA would continue to use capacity on the line to serve its Southeast Idaho load, but instead of owning capacity, BPA would purchase transmission service across B2H through Idaho Power's OATT. In Final Comments, Staff continued to address concerns over this potential ownership change because of unknown additional costs and ratepayer risks. Staff also addressed some of STOP B2H's analysis of the line, highlighting that although Staff agreed with cost risks related to co-participant changes, Staff agreed with the practice of reserving CBM capacity for emergencies. Staff also noted that issues revolving around EFSC siting were outside the scope of the IRP, and Staff indicated it did not agree that the addition of B2H would serve as a detriment to the system because of line loss increases.

In addition to cost concerns, Staff discussed the selection of B2H in the preferred portfolio. Staff will elaborate on this topic further on in this Staff Report when it discusses portfolio modeling.

<u>Idaho Power's Position</u>
Idaho Power continued to defend B2H as a "top performing resource alternative" in its Reply Comments.[26] It indicated that B2H is essential to facilitating its clean energy goals and assured that PacifiCorp and BPA "demonstrated ongoing financial commitment" to the project.[27] Idaho Power countered a number of STOP B2H's criticisms of the project, stating that the project costs were not understated and that the Company was not required to request a waiver of the competitive bidding rules. The Company also said that emergency transmission capacity in the form of CBM does not offset the need for B2H and that B2H will reduce line losses in the Western system. Finally, the Company argued that EFSC's rules governing issuance of a Site Certificate are inapplicable to the 2019 IRP.

In its Final Comments, Idaho Power responded to stakeholders' concerns about project participants by assuring that "Idaho Power's B2H Partners Remain Committed to the Project"[28] and that ownership or service arrangements would not affect B2H's 2026 in-service date. The Company said that it would not agree to arrangements shifting cost risk to retail customers without a "corresponding increase in benefits,"[29] and that the continued 21 percent ownership assumption in the IRP was appropriate.

[26] LC 74, Idaho Power's Reply Comments, page 3.
[27] LC 74, Idaho Power's Reply Comments, page 5.
[28] LC 74, Idaho Power's Reply Comments, page 5.
[29] LC 74, Idaho Power's Reply Comments, page 6.

Regarding the EFSC capacity and siting issue, Idaho Power stated that "it would be impossible for Idaho Power to utilize a 21 percent share of B2H unless 100 percent of the line is built,"[30] and that the Oregon Commission should reject STOP B2H's interpretation that the Commission's 2017 acknowledgment order only accounted for 21 percent of the line.

Staff's Analysis and Recommendations

Below is a table summarizing core stakeholder positions on B2H.

		Stop B2H	Carbiener	CUB	RNW	IPC Response	Staff Response
	Position	N	N	-	Y		
Against	Power Loss	X				Disagree	Disagree
Against	Excess Capacity Benefit Margin	X				Disagree	Disagree
Against	EFSC	X				Disagree	Disagree
Against	Competitive Bidding	X				Disagree	Disagree
Against	Co-Participant Risks	X	X	X		Parties are financially committed	Cost risk is a factor
Against	20 percent Contingency	X				Remove	Leave in
For	Access to clean energy/other markets				X	Agree	Agree
For	Improved Reliability				X	Agree	Agree
For	Regional transmission benefits				X	Agree	Agree
For	100% Clean Goal				X	Agree	Preferred Portfolio is inconsistent

The Company responded to Staff's recommendations by agreeing to incorporate cost sensitivities for B2H in the 2021 IRP and indicating that it would have ownership details finalized by the time the IRP is filed in 2021; it also appears amenable to modeling B2H cost risk sensitivities in the 2021 IRP.[31] Staff appreciates these inclusions for the next

[30] LC 74, Idaho Power's Reply Comments, page 15.
[31] LC 74, Idaho Power's Final Comments, page 8.

IRP cycle. However, the Company also indicates that it is considering removing or reducing the 20 percent cost contingency and that preliminary estimates show that the 2021 cost estimates for B2H are lower than in 2018.

Staff does not agree with removing the 20 percent cost contingency. While it is true that some large projects can stay under budget, cost overruns are not uncommon for projects like high-voltage transmission lines. Incorporating a cost contingency is standard practice for determining costs and is appropriate to include in the IRP. It is a conservative modeling choice that incorporates the genuine risk of cost overruns.

Staff also agrees with STOP B2H that the Company should update any costs to B2H before creating new portfolios for the 2021 IRP. Idaho Power indicates that it is already working with an engineering consultant to revise the B2H estimate for the 2021 IRP. Staff supports the Company's plans to include a breakdown of the cost estimate in the 2021 IRP.

As mentioned in Final Comments, there were a series of criticisms about B2H with which Staff did not agree. The concerns surrounding the following issues were not convincing in light of the evidence and arguments made by the Company:

- Line losses,
- The practice of reserving CBM capacity for emergencies, and
- The issues involving EFSC and the question of how much capacity the Oregon Commission acknowledged.

Regarding EFSC siting, the decisions of another agency are outside the scope of the IRP. However, in general, the higher the voltage of a line, the more capacity it allows. The highest capacity need for Idaho Power on B2H would be in the summer, when it is expected to reserve 500 MW of capacity. A transmission line facilitating only 500 MW is likely to be a different project at a different voltage, and would not be the same project the Commission acknowledged. When the Commission acknowledged B2H in the 2017 IRP, it is reasonable to assume that it understood it was acknowledging a 500 kV line.

Staff also believes that B2H is not subject to the competitive bidding guidelines. Order No. 18-324 states that the Commission revised the rules "to clarify that the competitive bidding requirements do not generally apply where a utility is seeking to exclusively acquire transmission assets or rights."[32]

Staff continues to be concerned about increased cost risk as a result of shifts in ownership. Even though the Company insists that it will not "reach any deal with BPA

[32] Order No. 18-324, page 6.

that would harm retail customers or the Company's shareholders," Staff still believes it is appropriate to consider the potential risk of additional costs for the project in the 2021 IRP. The Company may produce a range of sensitivities where, for example, customers are held harmless despite an ownership change, and others where customers assume additional cost risk as a result of the ownership changes. In the event that Idaho Power is unable to secure a new ownership agreement prior to filing the 2021 IRP, awareness of cost risk would help inform the Commission and stakeholders. Staff also believes the Company should dedicate time in an IRPAC meeting during the 2021 IRP to address how the Company plans on incorporating risk and that it include addressing the following questions:

- What are the specifics of the ownership arrangements the Company is considering?
- What is the risk that costs would increase under new arrangements?
- What sort of capital risk would Idaho Power be taking on by assuming additional ownership?
- How would these risks impact the Preferred Portfolio in an IRP?
- How is the Company going to model this risk in the 2021 IRP cycle?
- What would be the specific accounting authorizations needed for such an arrangement?
- What actions will Idaho Power take to minimize supply chain risk?
- What would be the specific types of contracts needed for such an arrangement?
- Would a change in partnership or service arrangement affect the in-service date of B2H?
- Is there still a possibility that another third party could assume ownership?

Selection of B2H in the preferred portfolio hinges on the Company's portfolio analysis. Staff addresses the issue of B2H acknowledgment further in this Staff Report under the section on Portfolio Design. Staff continues to recommend acknowledgement for the construction of B2H, but Staff believes the Company must demonstrate that it is able to optimize for Idaho Power's customers in the 2021 IRP.

Staff Recommendations:

- **Acknowledge Action Item 3, Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).**
- **Acknowledge Action Item 4, Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.**

Recommendations for the 2021 IRP:

- **Continue to include the 20 percent cost contingency for B2H in the 2021 IRP.**
- **Update B2H costs prior to creating new portfolios in the 2021 IRP.**
- **Model cost risk as it relates to a change in ownership arrangement in the 2021 cycle. This could be in the form of a series of sensitivities, where the Company continues to own 21 percent of the line and retail customers are held harmless, and introduce additional costs to customers based on a range of capital risks.**
- **Dedicate time in a 2021 IRPAC meeting addressing the issue of B2H cost risk as a result of new ownership structures. In the meeting, the Company should address the following questions:**
    - What are the specifics of the ownership arrangements the Company is considering?
    - What is the risk that costs would increase under new arrangements?
    - What sort of capital risk would Idaho Power be taking on by assuming additional ownership?
    - How would these risks impact the Preferred Portfolio in an IRP?
    - How is the Company going to model this risk in the 2021 IRP cycle?
    - What would be the specific accounting authorizations needed for such an arrangement?
    - What actions will Idaho Power take to minimize supply chain risk?
    - What would be the specific types of contracts needed for such an arrangement?
    - Would a change in partnership or service arrangement affect the in-service date of B2H?
    - Is there still a possibility that another third party could assume ownership?

VER Monitoring

VER Monitoring is addressed in Action Items 5 and 8: Action Item 5 is to monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units. Action Item 8 is to conduct a VER Integration Study.

Idaho Power's Analysis

The Company indicated in its latest VER study that Idaho Power's system may be nearing a point where current reserve-providing resources like dispatchable thermal and hydro will no longer be able to integrate additional VERs unless Idaho Power takes additional action to address potential reserve requirement shortfalls.[33] The Company does not specify what these actions are in the IRP, but additional details can be found in the 2018 VER report. Both of these Action Items are marked for 2020.

Stakeholder Positions

CUB
While CUB did not directly comment on these Action Items, it recommended that Idaho Power develop draft plans for potential Demand Response (DR) programs and include these in its future Demand Side Management (DSM) report or as a part of its VER Integration Study.[34]

RNW
Regarding the VER Integration Study, RNW suggested that Idaho Power ensure that stakeholder participation and collaboration are robust, because it believes that "stronger participation by knowledgeable parties will help to ensure accurate study results and facilitate greater integration of new, cost-effective renewable resources."[35]

STOP B2H
STOP B2H did not directly comment on these Action Items but remarked in Opening Comments on the *Amended* IRP that the time lag in the addition of VERs was too long "given the emerging threat of climate change and the declining price of VERs."[36] It did not replicate these comments for the *Second Amended* IRP.

Staff's Analysis and Recommendations

In Opening Comments, Staff reflected that AURORA was still selecting some solar while retiring thermal resources in this IRP, but it is necessary and appropriate for the Company to continue working with Staff in developing VER integration studies. Staff looked forward to working with the Company on this issue.

Staff believes it is prudent of the Company to continue to study VER integration and the impacts of resources like Jackpot Solar on the Company's system, in addition to the Company's reliability needs. However, because both Action Items 5 and 8 are marked for 2020, Staff does not believe it is appropriate to recommend acknowledgment for these Action Items. Staff is very interested in reading the results of these Action Items

[33] UM 1793, Idaho Power Company Application for Approval of Solar Integration Charge, page 1.
[34] LC 74, CUB Final Comments, page 5.
[35] LC 74, RNW's Opening Comments, page 6.
[36] LC 74, STOP B2H Opening Comments, page 47.

once they are published and recommends that the Company file each of these with the Commission once they are complete.

Staff Recommendations:

- ***Not Acknowledge Action Item 5: Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.***
- ***Not Acknowledge Action Item 8: Conduct a VER Integration Study.***

Additional Recommendation:

- **File the results of each of the VER studies with the Commission once they are complete and notify the LC 74 service list.**

Exit Boardman
Action Item 6 is to Exit Boardman December 31, 2020.

Idaho Power's Analysis
The Boardman closure has been a component of the Company's IRP for years. The Company retired the Boardman plant in 2020, and this resource decision continued to be selected as part of the least cost/least risk portfolio in the 2019 *Second Amended* IRP. This Action Item is marked for 2020.

Stakeholder Positions

CUB
CUB indicated in its Final Comments that though it supported the Company's decision to exit Boardman, since this is a completed action, it did not believe that it should be acknowledged by the Commission as a part of this IRP.[37]

Idaho Power
In Idaho Power's Final Comments, the Company agreed with CUB that exit from Boardman cannot be acknowledged because the Action Item has already occurred.[38]

Staff's Analysis and Recommendation:

[37] LC 74, CUB Final Comments, page 4.
[38] LC 74, Idaho Power Final Comments, page 46.

Staff agrees with CUB and Idaho Power that this Action Item should not be acknowledged because it has already been completed.

Staff Recommendation:

- ***Not Acknowledge Action Item 6: Exit Boardman December 31, 2020.***

Regional Haze
Action Item 7 is to have the 2020 Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.

Idaho Power's Analysis
The four Jim Bridger units are assumed to reach the end of their depreciable lives in 2034. Units 1 and 2 currently require selective catalytic reduction (SCR) investments in 2021 and 2022 for continued unrestricted operations through 2034. The SCR investments on Units 1 and 2 are not currently planned or included in the IRP analysis. PacifiCorp has submitted an application to the State of Wyoming for a Regional Haze Reassessment, which could provide an alternative to SCR installation on Units 1 and 2.[39] The negotiation with the Wyoming Department of Environmental Quality (DEQ) to extend the utilization of Jim Bridger Units 1 and 2 without SCR investments to comply with the Federal Clean Air Act Regional Haze rules has not yet been completed.[40]

Stakeholder Positions

Sierra Club
Sierra Club was concerned that PacifiCorp's delayed retirement of Jim Bridger was not designed to protect ratepayers, but rather to protect the utility in Wyoming, a state opposed to the closure of noneconomic coal plants. While these events would not impact the ratepayers of Oregon, Sierra Club was concerned that PacifiCorp might seek to block Idaho Power's early exit, calling the failure to negotiate for an early exit a prospect that would "adversely impact customers economically."[41] Sierra Club pointed to the fact that Idaho Power identified this as one of the "highest partner risk" among this IRP's Action Items.[42] Sierra Club held that PacifiCorp's election to maintain the Bridger coal plant should not be allowed to impose a risk or a cost on Idaho Power's

[39] Second Amended 2019 IRP, p. 98.
[40] Second Amended 2019 IRP, p. 98.
[41] Sierra Club Opening Comments, p. 4.
[42] Sierra Club Opening Comments, p. 4.

customers.[43] Given the near-term timeline of Idaho Power's proposed exit, and the risk posed by PacifiCorp's election to maintain the first unit longer than Idaho Power finds economic, Sierra Club wanted the Commission to direct Idaho Power to report back to this Commission by the end of calendar year 2020 on its exit negotiations with PacifiCorp.[44]

Staff's Analysis and Recommendation

The Action Item regarding the Unit 1 and Unit 2 Regional Haze Reassessment was for 2020. Because it is now 2021, Staff recommends that the Commission not acknowledge it. However, Staff recommends that the Commission require Idaho Power to file an update with the Commission when it knows the outcome of PacifiCorp's negotiation with the Wyoming DEQ regarding continued use of Units 1 and 2 without SCR investments. In addition, Idaho Power's 2021 IRP should include updated information regarding Idaho Power's exit from Jim Bridger Units 1 and 2.

Staff Recommendation:

- ***Not acknowledge Action Item 7: Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.***

Additional Recommendation:

- **Update the Commission as soon as it knows the outcome of PacifiCorp's negotiation with the Wyoming DEQ regarding continued use of Jim Bridger Units 1 and 2 without SCR investments.**

Valmy Unit 2 Exit

Action Items 9 and 13 are related to the Valmy Unit 2 exit. Action Item 9 is to conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2. Action Item 13 is to exit Valmy Unit 2 by December 31, 2022.

Idaho Power's Analysis

In the process of revising its *Amended* IRP, the Company undertook additional analysis and ran sensitivities that included a 2022 retirement date for Valmy Unit 2. In the *Second Amended* IRP, Idaho Power subsequently discovered that it is possible to

[43] Sierra Club Opening Comments, p. 4.
[44] Sierra Club Opening Comments, p. 4.

economically retire Valmy Unit 2 in 2022 instead of 2025 as originally planned. Table 9.7 of the IRP contains new portfolios with a 2022 retirement date. As the Company indicated in its IRP, it will perform a near-term analysis related to market depth, reliability, and other factors associated with Valmy transmission capacity prior to filing its 2021 IRP.

Stakeholder Positions

RNW

RNW generally supported the finding that a 2022 exit for Valmy Unit 2 would provide net economic benefits to Idaho Power and its customers. It also highlighted that Idaho Power should conduct a transparent stakeholder engagement on this early retirement process and implications of the reliability analysis. RNW recommended that this should include information about the type of model, inputs, assumptions, scenarios, and outputs that the Company will use in its reliability analysis.

CUB

CUB indicated that it appreciates the analytical adjustments leading to the early exit date for this coal plant and that it is confident that further cost and reliability analyses would leave this resource selection unchanged. CUB recommended that the Commission acknowledge this Action Item.

Staff's Position

In Final Comments, Staff indicated that though it did not oppose an early retirement of Valmy, it was not comfortable recommending acknowledgment without the required analysis the Company indicated should occur. The Preferred Portfolio selected 2025 as an optimal retirement year, and this was the same year acknowledged in the 2017 IRP. Staff supported amending the Action Item to reflect a 2025 retirement date until the Company performed the appropriate studies on reliability impacts for a Valmy shut down by the 2021 IRP filing.

Idaho Power's Position

Idaho Power appreciated Staff's perspective that more analysis should be performed to support a final decision on the appropriate exit date. The Company indicated that it selected 2022 due to cost modeling results and that the 2022 exit for Valmy showed cost savings as compared to the 2025 exit. Pending Commission approval, Idaho Power stated it was amenable to change the Action Plan to reflect a 2025 exit date for Valmy. However, it also stated that the Company is required to provide 15 months' notice to the ownership partner, NV Energy, prior to exiting Valmy and that this means Idaho Power has until September 2021 to provide NV Energy with enough notice of a year-end 2022 exit date.

Staff's Analysis and Recommendations

Staff continues to believe that investigating reliability impacts of early Valmy retirement and other factors is worthwhile. Where Staff would support potential cost savings of an early retirement, Staff believes it is reasonable to wait until the Company has conducted the appropriate studies. Pending Commission approval, Staff recommends that the Company retain the original exit date until Idaho Power has completed its analysis. Staff also supports a Commission filing similar to the Valmy Unit 1 closure where a more detailed cost analysis could be investigated by the Commission.

Staff Recommendations:

- **Acknowledge Action Item 9: Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2.**
- ***Not Acknowledge Action Item 13: Exit Valmy Unit 2 by December 31, 2022.***

Additional Recommendation:

- **Change the Action Item to include a Valmy Retirement in 2025 until the Company has completed the appropriate analysis to show 2022 is an optimal retirement date.**

Jackpot Solar
Action Item 12 is to have Jackpot Solar 120 MW on-line December 2022.

Idaho Power's Analysis
For the 2019 IRP, the Company is requesting acknowledgment for a 120 MW solar power purchase agreement (PPA) called Jackpot Solar. On April 4, 2019, Idaho Power notified the Oregon Commission about its intent to acquire this resource because it was a "time limited opportunity."[45] Oregon utilities must comply with the competitive bidding requirements for acquisition of certain generation resources or contracts unless they file a waiver for good cause.[46] Jackpot Solar meets the criteria under these requirements,

[45] LC 68, Idaho Power Company's Notice of Exception under OAR 860-089-0100. Accessible at https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf.
[46] OAR 860-089-100(1).

so the Company filed a Notice of Exception under the competitive bidding guidelines. Idaho Power indicated that it was approached by Jackpot Solar in September 2018 and that "Jackpot Solar offered to sell to Idaho Power 120 MW of renewable solar generation with very low pricing, significantly below both market prices and Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates."[47] The Power Purchase Agreement (PPA) is for the purchase of 120 MW of solar with an option to purchase an additional 100 MW at the Contract Price. Idaho Power includes this resource as part of its Preferred Portfolio and Action Plan.

Stakeholder Positions

CUB

CUB did not dispute that the Jackpot Solar PPA is a proper use of the OAR 860-089-100(3)(b) exception to the Commission's competitive bidding guidelines. However, CUB also did not wish to make a determination regarding the prudence of the Company's action in executing the PPA. CUB's concern with the PPA's inclusion in the IRP is based on procedural grounds; because the PPA is already signed, CUB believes that including it in the IRP for Commission acknowledgement runs contrary to established Commission precedent.[48] CUB also stated that a project being substantially complete was inappropriate for Commission acknowledgement.[49]

STOP B2H

STOP B2H extensively quoted analysis from an Idaho PUC docket whereby Idaho PUC Staff determined that the Jackpot Solar PPA was cheaper than Mid-C market purchases at the Mid-C, and that it provided Idaho Power's customers with less expensive, clean renewable energy over a 20-year period.[50]

Staff's Position

Similar to CUB, Staff indicated that Jackpot Solar appears to be a cost-effective PPA, but it also expressed concern with the Commission acknowledging a project for which a utility requested a waiver of competitive bidding rules. Staff recommended that the Company either clarify or remove this Action Item from the Action Plan.

Idaho Power's Position

In Opening Comments to the *Amended* IRP, Idaho Power clarified that AURORA was able to select the Jackpot Solar PPA as a cost-effective resource rather than a resource

---

[47] LC 68, Idaho Power Company's Notice of Exception under OAR 860-089-0100. Accessible at https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf.
[48] LC 74, CUB Opening Comments, pages 2 and 3.
[49] LC 74, CUB Opening Comments, page 3.
[50] LC 74, STOP B2H Final Comments, page 30.

based on capacity or energy need. In the Amended IRP, AURORA selected the Jackpot Solar PPA in the majority of the 24 WECC-optimized portfolios. However, because the decision to acquire Jackpot Solar was time bound, it agreed that the Jackpot Solar Action Item should be removed. Staff notes that it did not remove this Action Item in the *Second Amended* IRP.

Staff's Analysis and Recommendations
Staff maintains its position from Opening Comments that it is concerned with the Commission acknowledging a project for which a utility requested a waiver of competitive bidding rules and recommends not acknowledging this project. While it appears to be a cost-effective opportunity, Staff agrees with CUB that a Commission acknowledgment would be inappropriate based on Commission direction. The Company may still pursue cost recovery on this project in a rate case.

Staff Recommendation:

- ***Not Acknowledge Action Item 12: Jackpot Solar 120 MW on-line December 2022.***

Issues Outside of the Action Plan Raised by Stakeholders

Portfolio Analysis
Because the *Second Amended* IRP developed new portfolios, Staff considers the portfolio analysis and corresponding stakeholder comments in the *Amended* IRP to be largely obsolete. Thus, Staff will only discuss parties' Final Comments in this section of the Staff Report.

Stakeholder Positions

RNW
In general, RNW supported the changes to Idaho Power's portfolio analysis, including the accelerated Valmy retirement, procurement of new solar resources, "and the development of new transmission as a least-cost and carbon-free supply-side resource." However, RNW also strongly encouraged Idaho Power to study wind and solar resources paired with batteries, or battery energy storage systems (BESS) for the 2021 IRP. RNW indicated that these resources could supply energy during peak demand in addition to providing grid services.

STOP B2H
STOP B2H indirectly critiques the preferred portfolio by pointing to disagreements behind some of the assumptions in the *Second Amended* IRP portfolio analysis. Most apparent is STOP B2H's contention with B2H costs and co-participant risk: "The numbers used to create the portfolios cannot be validated because we do not know the value/amount of the partner's contributions by Idaho Powers admissions."[51] Thus, because STOP B2H does not believe the B2H cost assumptions are accurate, it contended that the IRP should not be acknowledged. STOP B2H indicated that Idaho Power should develop a new suite of portfolios with verifiable B2H costs or to conduct a tipping point analysis to determine how many more costs could be absorbed by the preferred portfolio.

STOP B2H also disagrees with the way the Company has modeled carbon risk: "In fact, Idaho Power is projecting that in 2025, carbon emissions from their system will be 10.46% higher under their [P]referred Portfolio than they are today and will not even start to decline below today's level until 2029." STOP B2H believes Idaho Power should have done a stochastic analysis on the cost of carbon in the IRP.

STOP B2H also expressed concerns with the way Idaho Power modeled peaker O&M startup costs in the *Second Amended* IRP because, according to STOP B2H, the Company "made changes in peaker cost inputs to AURORA for the purpose of making the peakers look much more expensive to own and operate that they really are,"[52] and that "Idaho Power deliberately adjusted the AURORA model to artificially increase the portfolio NPV" so they could save money from repowering certain gas units.[53] STOP B2H also disagreed with the general changes to cost assumptions in AURORA in the *Second Amended* IRP.

Staff's Position
Staff analyzed the cost effectiveness of the preferred portfolio and concluded that the Preferred Portfolio performed well in some futures but was outranked in other futures. Staff attached an Appendix detailing the ranking differences and explained that it was unclear why the Company selected PGPC B2H (1) as the Preferred Portfolio. There was no single portfolio that outranked others in all futures, and in general, the portfolios performed differently depending on the type of future. Staff also spoke to the repetitive nomenclature of the futures and portfolios, as well as the lack of detail in delineating the steps in the portfolio creation process.

[51] LC 74, STOP B2H Final Comments, page 11.
[52] LC 74, STOP B2H Final Comments, page 26.
[53] LC 74, STOP B2H Final Comments, page 29. Danskin is a gas-fired power plant consists of simple cycle combustion turbines.

Regarding the Company's portfolio analysis, Staff believed that qualitative measures of risk should be consistently applied across portfolios. For example, in addition to cost, portfolios could be evaluated or ranked according to qualitative risk. Staff recommended reporting qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward.

Staff also reiterated concerns from Opening Comments that Idaho Power should ensure that its modeling methodology optimize for Idaho Power's customers. Staff recommended that the Company devote resources to improve its optimization analysis, that it address this issue in a 2021 IRP workshop, and that it should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.

Finally, Staff was concerned that the Company relied primarily on carbon and gas costs as a base for mitigating risk in the base WECC portfolio analysis. Staff did not object to comparing an expected case portfolio cost to the range of costs across differing scenarios, but Staff believed that factors other than gas and carbon costs should be used in order to gain a better indication of risk.

<u>Idaho Power's Position</u>

In Idaho Power's Final Comments, the Company committed to incorporating some of Staff's recommendations in the 2021 IRP by improving portfolio naming conventions, incorporating qualitative risk measures in the 2021 IRP, optimizing portfolios for the Company's system, and following Staff's recommendation to expand modeling scenarios in the 2021 IRP. The Company also responded to Staff's request for additional clarification on manual adjustments to portfolio development and various stages of the portfolio development process. However, the Company indicated that Staff's analysis of the Preferred Portfolio does not apply because Staff had referred to the incorrect table in the IRP. Idaho Power proceeded to provide additional detail on portfolio development.[54]

The Company disputed STOP B2H's claims about carbon risk, stating that it looked extensively at carbon price futures throughout the portfolio development process. It developed two of the three portfolio groupings under a high-carbon price scenario to incorporate a range of possible policy futures. In this way, the Company believes it properly accounted for carbon price risk. Idaho Power disputed STOP B2H's comments about carbon emissions, and instead of focusing on Langley Gulch, the Company indicated that, because generation from its thermal resources has declined, its carbon

[54] LC 74, Idaho Power Final Comments, page 38. Staff referenced Table 9.5, but the Company indicated that Table 9.6 was the correct table in which to analyze portfolio costs.

emissions have also decreased between 2013 and 2019.

Regarding B2H costs, the Company expects that a more detailed analysis of B2H cost and risk will be part of the 2021 IRP because it will have finalized the details of the ownership and cost responsibility arrangements for B2H prior to its next IRP filing.[55] Regarding gas O&M costs, Idaho Power explains that in its review process, it discovered that in the *Amended* IRP, startup costs were not included, "which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected."[56] For the *Second Amended* IRP, the Company's new cost assumptions accounted for more costly start-up processes in peaking dispatch, and as a result, disfavored gas peakers.

In addition to the Company's Final Comments, Idaho Power hosted another call with Staff to answer additional questions about the portfolio development process and the Company's Final Comments. Staff appreciates the Company's efforts.

Staff's Analysis and Recommendations

Staff is pleased that the Company will be incorporating various Staff recommendations in the 2021 IRP, particularly regarding modeling cost risk as a result of potential ownership changes of B2H.

In general, Staff supports changes to the IRP that reflect actual Company operations, or how it expects to operate. To the extent that Idaho Power is modeling its gas peaker O&M and gas costs more appropriately, Staff is not opposed to those changes. Regarding carbon emissions and modeling carbon risk, the current IRP guidelines do not require stochastic analysis for measuring carbon cost risk.[57] The Company's HGHC portfolios provide alternative scenarios in which the Company entirely eliminates thermal resources, and despite the relatively high cost of these portfolios, in Staff's view, this analysis is consistent with IRP Guideline 8.[58]

Idaho Power indicated in its Final Comments that Staff used the wrong table for analysis, but analysis of the correct table brought similar conclusions. After the Company filed its Final Comments, Staff ran the same analysis on Table 9.6 and found very similar results—namely that the Preferred Portfolio weakly outranks the rest. While the Preferred Portfolio PGPC B2H (1) is the top ranking portfolio in the Planning Gas,

[55] LC 74, Idaho Power Final Comments, page 11.
[56] LC 74, Idaho Power Final Comments, page 54.
[57] Order No. 08-339.
[58] See updated Guideline 8 under Order No. 08-339.

Planning Carbon future, it does not perform as well in other futures. The ranks of the portfolios depend entirely on the type of future the Company is modeling.

Part of the Company's justification for the selection of the Planning Gas, Planning Carbon future is that it is the "most likely future scenario,"[59] and that "[n]ot all futures have equal probability of occurrence and the Company considers the results of the planning forecasts to be more significant."[60] This implies that the Company may have applied weights in calculating the rankings, but Idaho Power does not explicitly state this, and if it did apply weights to calculate rankings, it does not explain how it calculated those weights, or how it knows which future is more probable than the next.
Idaho Power also explains that "no other portfolio outranked the selected Preferred Portfolio when averaging the rank across all four futures."[61] While this is technically correct, Staff found that PGHC (1) had an average ranking equivalent to the preferred portfolio, assuming the Company applied equal weights across all futures.

While Idaho Power may have applied "common sense" industry judgment as to why Planning Gas, Planning Carbon is the more likely future and therefore most reasonable context for selecting the preferred portfolio PCPG B2H (1), it unfortunately does not outline its reasoning or analysis behind this logic in its IRP. As a result, the analysis shows that the Preferred Portfolio continues to be weakly defended.

Staff does caution that in other more cost-effective futures where B2H is not selected, replacement resources include hundreds of MW of natural gas, and given the carbon policy environment of states within the Western footprint, and the Company's own 100 percent clean by 2045 goal, it is unclear how the addition of gas turbines would fare in a policy environment hostile to fossil fuels. The High Gas, High Carbon (HGHC) portfolios in which the Company manages to avoid gas resources generally rank very low in terms of cost-effectiveness. The addition of the wind PTC in the 2021 IRP, updated costs for B2H, improved assumptions for capacity to contribution, and an updated VER integration study should provide a more informed picture of the lowest-cost portfolios moving forward.

Further, Staff compared the 2019 Action Plan to the 2017 Action Plan, and very little has changed in terms of resource acquisition within the Action Plan window. The major changes are that the Company is adding 120 MW of solar through the acquisition of Jackpot Solar, and the Company may retire Valmy three years earlier than in the 2017 IRP Action Plan. The other main resource acquisition is B2H, of which the Company has not yet begun construction. In Final Comments, Staff indicated that the issue of

[59] LC 74, Idaho Power Final Comments, page 42.
[60] LC 74, Idaho Power Final Comments, page 42.
[61] LC 74, Idaho Power Final Comments, page 42.

ownership details and project cost risk is a material issue, and the Company must finalize these details prior to the filing of the 2021 IRP. Staff has recommended acknowledgment of B2H in the past, but the Company still has a responsibility to provide material updates and address capital cost or increased cost risk as a result of new participant arrangements.

Recommendations for the 2021 IRP:

- **Report qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.**
- **Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.**
- **Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.**

Energy Efficiency

Idaho Power's Analysis

While Idaho Power tested alternative energy efficiency potential forecasting methods in the 2019 IRP, the underlying initial potential study was the same as the 2017 IRP methodology and served as a base case for comparison purposes. For the 2019 IRP, Idaho Power's third-party contractor provided a 20-year forecast of Idaho Power's energy efficiency potential from a total resource cost (TRC) perspective. The contractor also provided additional forecasts based on different economic scenarios.[62] The 20-year energy efficiency potential included in the 2019 IRP declined from 273 aMW in the 2017 IRP to 234 aMW in the 2019 IRP. System on-peak potential from energy efficiency also declined from 483 MW to 367 MW from the 2017 IRP to the 2019 IRP.[63] Idaho Power attributes most of this decline to the reduction of available residential lighting measures

[62] Second Amended 2019 IRP, page 58.
[63] Second Amended 2019 IRP, page 61.

after the 2020 effective date of the 2007 Energy Independence and Security Act manufacturing standard.[64]

<u>Stakeholder Positions</u>

STOP B2H

STOP B2H recommended that the Company reevaluate and improve its energy efficiency programs and increase energy efficiency in its preferred portfolio. STOP B2H observed that Idaho Power has implemented a limited number of pilots and new programs and suggested this indicates insufficient commitment on the Company's part in providing the appropriate level of energy efficiency services. STOP B2H also asserted that the Company's low energy efficiency targets are set too low and therefore impact resource forecasting needs.

<u>Staff's Position</u>

In Idaho Power's 2017 IRP, stakeholders and Staff were concerned that Idaho Power was not pursuing all cost-effective energy efficiency. The Commission approved Staff's recommendation that Idaho Power "report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology" in its 2019 IRP.[65] Idaho Power did not include such a report in its original, Amended or Second Amended IRP.

Further, Idaho Power has consistently acquired more energy efficiency savings than targeted in the past several years. Staff believed that improving the IRP forecast of target energy efficiency savings could better reflect the cost-effective achievable energy efficiency that may be available.

Finally, the Idaho Public Utilities Commission (IPUC) has ordered Idaho Power to screen measures using the Utility Cost Test (UCT) as the primary test. Previously, the IPUC had required Idaho Power to use both the UCT and the Total Resources Cost (TRC) test, as is done in Oregon. It was unclear to Staff how Idaho Power's reliance on the UCT to screen for energy efficiency in its Idaho service territory will impact energy efficiency offered in Oregon.[66] Accordingly, Staff recommended that Idaho Power address the impact of the change in the screening test in Idaho on Oregon energy efficiency in the 2021 IRP.

---

[64] Second Amended 2019 IRP, page 61.
[65] LC 74, Staff Opening Comments, page 10.
[66] LC 74, Staff Opening Comments, page 12.

Idaho Power's Position

In response to Staff's recommendation to review energy efficiency measures undertaken by other utilities, Idaho Power committed to a review of ETO's piloted measures from 2018-2020, and to share the results of the review with its Energy Efficiency Advisory Group ("EEAG") during a 2021 EEAG meeting in preparation for Idaho Power's 2021 IRP.[67] Idaho Power stated that it has expanded the IRP process to include an energy efficiency subcommittee as part of the 2021 IRP that includes a variety of stakeholders, including STOP B2H and OPUC Staff.[68]

In response to B2H's assertion that Idaho Power's energy efficiency savings have remained relatively static since 2015, Idaho Power states it has had an increase of 25 percent savings from 2015 to 2019, and in 2019 achieved its highest energy efficiency savings since Idaho Power's Energy Efficiency Rider was established in 2002.[69] Idaho Power acknowledged that energy efficiency acquisition decreased after 2019, but asserted that is due primarily to the Energy Independent Security Act, which was expected to tighten lighting standards starting January 1, 2020.

In response to STOP B2H's claim that the Company's energy efficiency targets are set too low and therefore impact resource forecasting needs, the Company asserted that it contracts with a third party to evaluate and identify energy efficiency measures that could be used in Idaho Power's territory and that its energy efficiency targets are consistent with energy standards.[70]

Idaho Power stated that it does not know how the change to using the UCT as the primary screening criteria will impact energy efficiency potential. It committed to comparing the two approaches through a third-party energy efficiency potential study to see differences at the economically achievable level and to holding a workshop on prior to finalizing the energy efficiency potential study.

Staff's Analysis and Recommendation

As noted in Staff's Opening and Final Comments, it is not possible to tell from Idaho Power's 2019 IRP all the energy efficiency measures Idaho Power explored in addition to those included in the Company's IRP Action Plan. This lack of clarity contributes to the Staff and stakeholder concerns that Idaho Power is not pursuing all cost-effective energy efficiency in its Oregon territory. Accordingly, Staff recommends that Idaho Power conduct a comprehensive review of the programs offered through the Energy Trust of Oregon (ETO) in the last three years, and for each measure, report on whether

[67] LC 74, Idaho Power Company's Final Comments, page 57.
[68] LC 74, Idaho Power Company's Final Comments, page 56.
[69] LC 74, Idaho Power Company's Final Comments, page 57.
[70] LC 74, Idaho Power Company's Final Comments, pages 57-58.

the Company considered it, what research the Company did, and what the Company decided with respect to the measure.

In its Reply Comments Idaho Power committed to a review of the ETO measures from 2018-20 and to share the results with its EEAG. Staff appreciates Idaho Power's commitment and notes that it is important that the report provided to its EEAG provide sufficient information to answer the questions identified in Staff's recommendation. Staff also appreciates Idaho Power's commitment to investigate how its switch to using only the UCT to screen for cost effective energy efficiency may impact the acquisition of energy efficiency, and to holding a workshop on this topic.

Regarding Staff's and Stop B2H's concerns that Idaho Power may be under forecasting the potential for cost effective energy efficiency in its service territory, Idaho Power stated that its approach to savings potential in the IRP is consistent with industry standards and that the achievable economic potential is "based on rigorous assessment of the available EE potential in Idaho Power's service area."[71] Staff anticipates that the information Idaho Power has committed to provide as it prepares its next IRP will help Staff and stakeholders investigate and address any concerns about whether Idaho Power is assessing energy efficiency potential adequately.

Recommendation for the 2021 IRP:

- **Review all energy efficiency measures piloted by Energy Trust in 2018-2020 and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. The Company should share the status of its review at an Energy Efficiency Advisory Group meeting in 2021 and as a report in the 2021 IRP.**

Load Forecast

Idaho Power's Analysis
Idaho Power produced separate forecasts for each major customer class. The residential load forecast is the product of a use-per-customer and customer count forecast. The use-per-customer forecast is based on ITRON's Statistically Adjusted End Use Model (SAE). This model utilizes an adoption rate forecast for energy efficient

[71] LC 74, Idaho Power's Final Comments, page 58.

items like high efficiency washing machines and low energy light bulbs to inform the model on expected usage patterns of customers in Idaho Power's service territory. These forecasts of customer end-use demand are then used to inform a standard regression model to produce a use-per-customer amount. Industrial and Commercial sectors are broken down into services and manufacturing, then further broken down into 12 subsets (e.g. dairy, food packaging, etc.). Historic usage, weather, and economic and demographic data are used to inform all of the models. The Company also uses separate forecasts for on-site generation and electric vehicles to adjust the use-per-customer forecast. It is Staff's understanding that the Company retained the same load forecast for the *Second Amended* IRP.

Stakeholder Positions

STOP B2H
In its Opening Comments, STOP B2H described a concern in which the Company's forecast did not necessarily match the pattern of historical values, in that load has remained flat in recent years. STOP B2H argued that a simpler load forecasting model would be better at predicting load. In its Final Comments, STOP B2H argued that Idaho Power over forecasts sales and that the increase in Idaho's residential population has been proportional to a decrease in average residential use. It argued that this trend is also demonstrable in both the industrial and commercial sectors. It proposes alternative mathematical methods to forecasting load.

Sierra Club
In Opening Comments, Sierra Club stated that Idaho Power's peak load growth assumptions were aggressive, resulting in a shift towards capacity resources, and that the post-2007/2008 recession growth was impacting the load forecasts. Further, Sierra Club indicated that future IRP analysis should be more comprehensive and take advantage of opportunities for controlling future peak load growth using clean resources consistent with Idaho Power's 2045 objective.

Staff's Position
In Opening Comments, Staff noted its concern with the Company's reliance on ITRON for load forecasting because ITRON's proprietary methods result in black box forecasts with limited access to the inputs that create the forecasts. As a second concern, Staff described the potential of non-stationarity/unit root in some of the Company's non-time-series based models.

In Final Comments, Staff indicated that the Company still needs to do more work to address potential non-stationarity. Staff maintained that a time series model should be used for time series data in order to prevent problems that can arise from incorrectly assuming that data is not correlated across time. Staff recommended that in its Final Comments, the Company identify the statistical method it will use to judge whether ARIMA[72] models can reduce forecast error, and that prior to its next IRP filing, the Company hold a workshop to present a statistical method addressing this issue. Finally, Staff requested that the Company present the impacts of the pandemic-related recession on long-term load growth as part of the 2021 IRP. Staff also made a series of load forecasting recommendations, most of which Staff repeats below.

Idaho Power's Position

The Company resolved Staff's first concern of not being able to access ITRON data by supplying Staff with a confidential work paper of the ITRON model inputs. Staff was able to use this work paper to review the Company's work. The Company also responded to Staff's concern of using non-time-series based models and potential non-stationarity by committing to using ARIMA error testing. The Company argued that more testing is needed to confirm that a time series model would not introduce inaccuracy. Idaho Power also replied to STOP B2H by arguing that its model appropriately considers the numerous and complex factors impacting load. In response to Sierra Club, the Company argued that its model results are reliable.

In Final Comments, the Company indicated it was committed to using ARIMA error testing and exploring other statistical models. It indicated that improvements pertaining to indicator variables within the Company's residential models and out-of-sample testing are expected to be included in future IRPs. Further, Idaho Power maintained that econometric models are the best available means for long-term load growth forecasting, and that weather-adjusted sales are increasing, contrary to STOP B2H's analysis.

Staff's Analysis and Recommendations

First, Staff notes that the Company already held Staff's requested load forecasting workshop on February 23, 2021, as part of the 2021 IRP Cycle. Staff appreciates that the Company accommodated Staff's recommendation.

In general, Staff stands by its Final Comments and looks forward to continued improvement in the 2021 cycle. Regarding the Company's Final Comments, Staff has one concern. On page 69 of Final Comments, the Company writes, "Staff asks Idaho Power to identify in Final Comments what statistical method the Company will use to evaluate whether ARIMA models can reduce forecast error." However, the Company did not identify its planned statistical method. Staff believes the Company should consider cross-validation, which is a technique that has been employed by Cascade Natural Gas Company in its 2020 IRP.

---

[72] Auto Regressive Integrated Moving Average.

Recommendations for the 2021 IRP:

- **Use a metric like the Akaike Information Criterion to confirm that indicator variables are not causing model overfitting.**
- **Present a plan for cross-validation or similar to check whether ARIMA models are likely to reduce load forecast error in the next IRP and check robustness of Idaho Power's load forecasting model.**
- **Address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.**
- **Present to Commissioners the impact of COVID-19 on load.**

Demand Response

Idaho Power Analysis

Idaho Power's original 2019 IRP Action Plan included acquisition of 5 MW demand response (DR) in 2026. After discovering its IRP modeling only dispatched DR in resource deficit situations, Idaho Power revised its modeling to treat DR as a resource to offset load, which resulted in additional DR in the preferred portfolio. The Company will not begin acquiring additional DR until 2031 and increases in DR in the Preferred Portfolio DR will occur in increments of 5 MW per year from 2031 to 2038.[73] The IRP is not clear if these additions represent new programs or expansions of existing programs.

Stakeholder positions

CUB

CUB expressed concern that Idaho Power had not sufficiently explored the host of available DR resources that utilities are deploying across the county,[74] but it also appreciated Idaho Power's expanded use of DR from a "lender of last resort" to a summer peak load resource, resulting in increase in DR acquisitions in the IRP.[75] CUB suggested that based on the successful use of DR to shave summer peak load, Idaho Power should be motivated to model DR as a resource to meet winter peak loads and explore winter DR programs, including direct load control of electric HVAC systems and water heating.

[73] 2019 Second Amended IRP, pages 62-64.
[74] LC 74, CUB Opening Comments, page 5.
[75] LC 74, CUB Opening Comments, page 5.

CUB was also concerned about the delay before the acquisition of DR, which is not until after 2030, and was concerned about Idaho Power's preparedness to acquire DR if it is needed more in the near-term. CUB explained that among other things, designing a DR program is a multistep process involving designing effective pilots, evaluating and learning, and then expanding it to a full-size program. CUB recommended that Idaho Power develop draft plans for potential DR programs and include these in its future DSM report or as a part of its VER Integration Study.[76]

STOP B2H

In its Final Comments, STOP B2H continued to be critical of Idaho Power's analysis and use of demand side resources in its IRP. Stop B2H noted the juxtaposition between the Northwest Power and Conservation Council's (NWPCC) Seventh Power Plan finding that DR is the cheapest way to meet capacity needs and Idaho Power's practice of using DR only after other resources are deployed.[77] STOP B2H acknowledged that Idaho Power has committed to use DR to shave peak loads but was concerned Idaho Power was not adequately capturing DR during the planning period.[78]

<u>Staff's Position</u>

Staff was concerned Idaho Power's modeled levelized cost of capacity (LCOC) of DR was too high. The average LCOC of existing resources is $29 per kW-year and the modeled LCOC of expanded DR resources is $60 per kW-year, a difference of more than 100 percent. In April 2020, Staff asked the Company to rerun the model varying the LCOC of expanded DR with values less than $60 per kW-year, e.g., a 10 percent increase over the existing resource of $29 per kW-year ($32 per kW-year), a 25 percent increase ($37 per kW-year), and a 50 percent increase ($44 per kW-year).

The Company did not re-run the model with lowered LCOC for DR. In Final Comments, Staff continued to be concerned that a LCOC for DR that is 107 percent greater than the average LCOC of existing resources was unrealistic. For Idaho Power's 2021 IRP, Staff recommended that Idaho Power model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.

<u>Idaho Power's Position</u>

In response to Staff's request to conduct more modeling using different assumptions for the LCOC of DR, Idaho Power indicated it is difficult to simulate future costs of DR

[76] LC 74, CUB Final Comments, page 6.
[77] LC 74, Stop B2H Final Comments, page 44.
[78] LC 74, STOP B2H Final Comments, pages 44, 48.

because it is a customer-based program. Idaho Power said it provided detailed assumptions regarding its assumptions for the LCOC of DR in response to Staff's Data Request 41 and in its Reply Comments. Idaho Power committed to providing a detailed explanation of cost estimates used in the LCOC for DR in the 2021 IRP.[79]

Idaho Power took issue with criticisms regarding the decrease in DR capacity since 2012, noting that Idaho Power and stakeholders executed a settlement agreement in 2013 agreeing the Company would not add new DR programs in years when the Company does not anticipate peak-hour capacity deficits.[80] Idaho Power notes that its Second Amended IRP does not identify a capacity deficit until 2026 and this deficit is met through a resource with broader availability than DR.

Idaho Power appreciated CUB's recommendation to explore use of DR for winter peak loads as well as summer peak loads, but stated that meeting summer capacity deficits generally means that winter capacity deficits do not exist. However, Idaho Power stated that if a capacity deficit developed with respect to the Company's winter peaks, the Company is open to future modifications of its DR analysis and balancing assumptions. Further, Idaho Power committed to analyzing the capability of DR to meet possible capacity needs or the 2021 IRP and to reporting on that analysis in the 2021 IRP.[81]

Staff's Analysis and Recommendation

Staff appreciates Idaho Power changing its modeling to dispatch DR to shave peak load and supports continued modeling of DR to offset load rather than as a resource of last resort. However, Staff continues to be concerned regarding the LCOC of DR modeled by the Company. The Company states that it is difficult to comply with Staff's request to simulate the LCOC of DR programs, noting the programs are not scheduled to deploy for another ten years. Staff is concerned the Company is creating an analytical loop in which DR is excluded as a high-cost resource. As CUB and Staff both point out, the Company should be modeling costs of DR acquisitions in the near future as well as ten years from now to ensure the most cost-effective portfolio is acquired. Idaho Power assumes DR will not be cost effective until after 2030 and bases this assumption on the cost of DR acquired more than ten years in the future. It is not clear, therefore, whether DR would be cost effective prior to 2030 if realistic assumptions about the LCOC of near-term acquisitions of DR are used. Idaho Power should rigorously test its assumptions about the cost effectiveness of DR in the next ten years.

[79] LC 74, Idaho Power Company's Final Comments, page 60.
[80] Idaho Power Company's Final Comments, p. 60.
[81] Idaho Power Company's Final Comments, p. 64.

Staff appreciates Idaho Power's commitment to provide detailed analysis regarding its cost assumptions in the 2021 IRP. However, Staff will continue to probe Idaho Power's use of an unreasonably high LCOC for DR and will look to ensure reasonable assumptions are used.

Recommendation for the 2021 IRP:

- **The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.**

DR and Battery Storage

Idaho Power Analysis
Idaho Power did not include a comparison of DR and battery storage in its 2019 Second Amended IRP.

Staff Position
In its Opening Comments, Staff asked the Company to address the extent to which DR can provide services similar to those of battery storage. Staff also asked the Company to explain the different LCOCs of DR programs and standalone battery-storage resources and notes the 2019 Amended IRP selects a battery resource earlier than DR. Staff also suggested pairing DR with solar.

Idaho Power Response
Idaho Power did not directly respond to Staff's inquiry regarding a comparison of battery storage and DR. However, Idaho Power stated that "Demand Response at Idaho Power is intended to be used for short-term deficits in order to minimize or delay the need to build new supply side resources."[82] In response to Staff's inquiry about pairing DR with solar resources, Idaho Power stated that a combined solar and DR program would likely result in a higher LCOC than any of the solar/battery combinations analyzed in the IRP.[83]

[82] LC 74, Idaho Power Company's Reply Comments, page 55.
[83] LC 74, Idaho Power Company's Reply Comments, page 60.

Staff's Analysis
Staff appreciates Idaho Power's responses to its inquiries regarding pairing of DR and solar. Staff notes that the selection of DR as a resource in the 2019 Second Amended IRP occurred at the same time as a battery resource, whereas in earlier versions of the IRP DR was selected after battery storage. Staff has no specific recommendations on this issue for the next IRP but will continue to engage with Idaho Power on this topic as Idaho Power prepares its 2021 IRP.

Time of Use Rate Offerings

Idaho Power's Analysis
Idaho Power does not include Time of Use rate offerings in its Preferred Portfolio.

Stakeholder Positions

CUB
CUB noted that Advanced Metering Infrastructure (AMI) deployment in Oregon is nearing completion and is scheduled to be complete by the end of 2020. With this resource in place, CUB recommended that Idaho Power initiate pilots such as critical peak pricing, peak time rebates, or time-of-use rates.

Staff's Position
Staff acknowledged that the Company currently offers an Oregon Residential Time-of-Day Pilot Plan and that Idaho Power will report on the pilot in its 2021 Smart Grid Report. However, Staff was unsure whether TOU rates will be explored as a cost-effective resource in the 2021 IRP. Idaho Power's modeling is based on $60 per KW-year LCOC for expanded DR, which is unrealistic for behavior-based programs that do not include hardware costs.

Idaho Power's Position
To date, there are three customers participating in the Time-of-Day (TOD) Pilot Plan, and there have not been any material costs associated with implementation or management of the offering. Due to the relatively low level of participation, the Company has not studied the impact of peak capacity reduction by season or time period, as the reported results would not be statistically valid. While the Commission suspended the Company's requirement to file a 2021 Smart Grid Report, Idaho Power believed it was reasonable to leverage the work that will be done in the Distribution System Planning docket (UM 2005) as an avenue to report on its TOD pilot. The Company also believed it was reasonable to evaluate the structure of TOD rates in a

future general rate case, or other proceeding where customer rates will be evaluated, to determine if other structures may be feasible.[84]

Staff's Analysis and Recommendation
Staff's concerns regarding Idaho Power's modeling of Time-of-Use rate offerings are the same as for other DR in Idaho Power's 2019 Second Amended IRP – Idaho Power generally has used unrealistic LCOC assumptions for all DR. However, Staff appreciates Idaho Power's commitment to continue its review of use of TOD rates in the DSP Planning docket and in future rate cases.

Recommendations for the 2021 IRP:

- **Provide an update on the Oregon Residential Time-of-Day Pilot Plan, including number of participants, total cost of the pilot since its 2019 launch, and peak capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the Smart Grid Report will be suspended with the Commission approval of DSP guidelines.**

- **Work with Staff and stakeholders to develop a new modeling approach suitable for behavior-based DR programs that reflects such programs' typical lower costs and less certain results.**

Qualifying Facilities (QFs)

Idaho Power's Analysis
Idaho Power indicated it cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. Generation from PURPA contracts is forecasted early in the IRP planning process to update the accounting of supply-side resources available to meet load. The PURPA forecast used in the 2019 IRP was completed in October 2018. Detail on signed PURPA contracts, including capacity and contractual delivery dates, is included in Appendix C—Technical Appendix.[85]

[84] LC 74, Idaho Power Company's Final Comments, page 65.
[85] Idaho Power Second Amended IRP, page 43.

Stakeholder Comments

REC

REC expressed concerns about the assumptions Idaho Power makes for QFs whose contracts are scheduled to terminate during the planning period. REC asked the Commission to direct Idaho Power to make appropriate planning assumptions about QF renewals and compensate QFs for this value.[86] REC argued that the IRP should assume that all QFs with expiring contracts will renew their contracts and that all renewing QFs should receive a capacity payment throughout the term of their Energy Service Agreements (ESAs).[87]

Staff's Position

In response to REC's concerns, Staff recommended that the Company describe what specific wind repowering developments would cause the Company to change its wind QF renewable assumptions. Staff noted there is risk inherent in assuming that none of the wind contracts will renew. For the 2021 IRP, Staff requested that the Company incorporate sensitivities related to QF wind renewals.[88]

Idaho Power's Position

Idaho Power disputed REC's contention that Idaho Power has improperly forecasted power purchase from QFs under PURPA; it stated that it has used the same methodology as in past IRPs and that it assumed all existing QF contracts, except for wind projects, will continue to deliver energy throughout the planning period.[89] The Company explained that it does not expect the wind projects to renew because the cost of repowering wind QFs can be very significant.[90] Given the wind Idaho Power currently has on its system, Idaho Power believes it would be unwise to simply assume, without a sound basis, that all of the wind capacity will be available in perpetuity.[91] Idaho Power stated it will continue with this assumption until information to the contrary comes available. Nonetheless, in response to Staff's suggestion, Idaho Power stated it will perform sensitivity analysis in its next IRP pertaining to wind replacement assumptions to evaluate the impacts on resource planning.[92]

With respect to REC's arguments regarding capacity payments to renewing QFs, Idaho Power points out that the Commission has not yet taken up the issue that REC

---

[86] LC 74, Renewable Energy Coalition's Opening Comments, page 10.
[87] See LC 74, Idaho Power Company's Reply Comments, page 66.
[88] LC 74, Staff Final Comments, pages 6-8.
[89] LC 74, Idaho Power Reply Comments, page 66.
[90] LC 74, Idaho Power Reply Comments, page 67.
[91] LC 74, Idaho Power Reply Comments, page 67.
[92] LC 74, Idaho Power Final Comments, page 67.

discusses in its comments and that the issue is properly addressed in an investigation regarding the avoided cost methodology, not review of an IRP.

Staff's Analysis and Recommendation

In absence of any particular methodology prescribed by the Commission, Staff does not find Idaho Power's forecast of QF purchases based on data known to Idaho Power and its assumptions regarding renewal of contracts to be unreasonable. Idaho Power's assumption that no wind QFs would renew their contracts based on the costs involved in repowering a wind resource is pragmatic given the amount of wind currently on Idaho Power's system. However, Idaho Power's assumption regarding wind QFs is not necessarily consistent with Idaho Power's own assumption that it will repower its wind resources.

In response to REC's and Staff's concerns, Idaho Power has committed to updating its assumptions regarding renewal of QF wind resources if and when new information becomes available. Staff believes that continually updating assumptions based on new data is an implicit requirement of the IRP process. Idaho Power has also committed to performing sensitivity analysis in its next IRP pertaining to wind replacement assumptions to evaluate the impacts on resource planning. Staff is satisfied with this commitment.

REC's request that the Commission order Idaho Power to compensate renewing QFs for capacity immediately upon renewal is out of place in this docket. This issue will be addressed in the Commission's general investigation into the avoided cost methodology in Docket No. UM 2000.

Recommendation for the 2021 IRP:

- **Perform sensitivity analysis in its 2021 IRP pertaining to wind replacement assumptions to evaluate the impact on resource planning.**

Resource Inputs

Idaho Power's Analysis
For the 2019 IRP, Idaho Power updated the capacity value of solar using the 8,760-based method developed by National Renewable Energy Laboratory (NREL), which

limited the approximation of solar capacity value to the highest 100 hours in the Company's load duration curve.

For gas prices, Idaho Power used a third-party vendor to estimate gas price forecasts. Based on an examination of the forecasting methodology and comparative review of various sources (i.e., Moody's and NYMEX), Idaho Power concluded that its third-party vendor's natural gas forecast was appropriate for the planning case forecast in the 2019 IRP.

Regarding resource input costs, on page 24 of Appendix C in the *Amended* IRP, the Company presented an LCOE for Wyoming wind of $94 MWh.

Stakeholder Positions

RNW
RNW recommended that Idaho Power explore options that might displace the gas peaker selected by the model in 2030. It also strongly encouraged Idaho Power to study wind and solar resources paired with batteries, or battery energy storage systems (BESS) for the 2021 IRP.

Staff's Position
In Opening and Final Comments, Staff expected that the Company would use the capacity value methodology stipulated in Docket No. UM 1719. In Order No. 16-362, the Commission established two standards for estimating the capacity contribution of variable energy resources in IRP planning: Effective Load Carrying Capability (ELCC) or a Capacity Factor (CF) approximation. Staff asked the Company to explain how the methodology used to derive wind capacity values complies with the stipulation approved by Commission Order No. 16-326 because it was concerned that Idaho Power was not in compliance with the order.

In Opening and Final Comments, Staff had concerns with the LCOE for Wyoming wind of $94 MWh. Staff believed that this was a significantly higher than most resource economics literature. Staff also questioned why the Company did not include wind Production Tax Credits (PTCs) as an input in AURORA.

Staff also looked into the AURORA modeling assumptions for battery storage and was concerned that the Company placed limits on the amount of storage allowed in its portfolios.[93] Based on the data provided to Staff, the amount of standalone storage available for selection in this IRP appeared to be limited to 80 MW per year, and the

[93] Aurora database provided to Staff for review.

amount of storage that can be paired with solar was limited to 80 MW over the entire planning timeframe.

Staff, along with other parties, also questioned the inclusion of a 300 MW gas generator in 2030 given Idaho Power's goal to be "Clean by 2045." This presented a possibility of a gas resource having a useful life of only 15 years, while the assumed useful life in the IRP's generic natural gas levelized cost of energy (LCOE) was 30 years. Staff sought clarification in an information request, to which Idaho Power replied, "The Company is looking for ways to meet or offset its future resource needs in accordance with its 2045 goals but acknowledges advances in technology may be required."[94]

Idaho Power's Position

Initially, in Idaho Power's Opening Comments, the Company indicated that it chose not to use the ELCC method because 1) it needed at least 3-5 years of additional data for certain components of the methodology, and 2) The ELCC method did not adjust for solar energy's changing capacity value as the total amount of solar on the Company's system increases. Idaho Power ultimately determined that NREL's approach to modeling solar energy's capacity value best fit the Company's system. However, in Final Comments, the Company recognized Staff's concern that "regardless of the superiority of the NREL's modified ELCC approach and the transparency with which the Company adopted this new method, the solar capacity valuation method applied in this case does not squarely align with the two methods identified by Commission Order No. 16-326."[95] Because it did not select one of the two methods, Idaho Power subsequently requested an exception from application of the order.

Regarding the selection of a natural gas resource in 2030, Idaho Power indicated that this resource is intended to be a placeholder or "surrogate" resource that would behave like natural gas in terms of flexibility and dispatchability. Idaho Power reiterated its focus on a 100 percent clean energy by 2045 goal, and expects that future technology development and cost changes "will ultimately determine what the flexible resource will be," and "anticipates technology advancements and associated cost declines will facilitate the replacement of natural gas with clean, flexible resources."[96]

In Final Comments, the Company addressed the PTC's absence from the 2019 IRP and indicated that a larger factor in fewer wind resources in the IRP was the resource's limited contribution to meeting the Company's summer peak.[97] For the 2021 IRP, the Company said it would model the PTC for wind to the extent it is technically achievable.

---

[94] See LC 74, Staff's Opening Comments, Attachment A, Idaho Power Response to Staff IRs 1-2.
[95] LC 74, Idaho Power's Final Comments, page 47.
[96] LC 74, Idaho Power's Final Comments, page 51.
[97] LC 74, Idaho Power's Final Comments, page 53.

Despite this agreement to model wind PTCs in the next IRP, Idaho Power said that Staff's Final Comments are inconsistent with Staff's position in the PGE IRP, and that "when PGE timed the development of a new wind project to take advantage of PTCs, Staff advocated to limit associated power cost recovery precisely because the project was timed to maximize PTC benefits."[98]

Regarding energy storage limitations, Idaho Power stated that for standalone storage, it did not limit the capacity to 80 MW. The Company provided a table showing storage solutions and total potential for each option modeled in the 2019 IRP.[99] However, it admitted that for solar *plus* storage, it did indeed limit the threshold to 80 MW and believed that it was reasonable because of "the typical size of battery storage projects, as well as the lack of any current battery storage on Idaho Power's system."[100] The Company agreed to evaluate higher limits for solar-plus-storage in the 2021 IRP cycle.

<u>Staff's Analysis and Recommendations</u>

For the Company's approach to the capacity contribution of solar, Staff does not disagree that 3-5 years of data is a reasonable requirement. Idaho Power explained that the rapidity of the solar penetration spike on its system meant that there was inadequate longitudinal data to perform the ELCC calculation. However, Staff believes it is possible to approximate the ELCC of solar from irradiance data for 3 to 5 years. While not based on actual data collected on the Company's system, an approximation would have been more consistent with the stipulation in UM 1719. The Company states it will have enough data to perform the correct calculation for the 2021 IRP. As a result, Staff is not opposed to an exemption for the 2019 cycle.

Regarding the high cost assumptions of Wyoming wind, Staff could not identify where the Company addressed Staff's questions around the high costs it assumed in the IRP. Staff is aware that the Company is in the process of completing the 2020 VER Integration study, which will incorporate more updated wind integration costs. As of writing this Staff Report, Staff is unaware of whether this report has yet been filed with the Commission. Staff asks that the Company notify the LC 74 service list once it files the 2020 VER Integration Study.

Staff also appreciates that the Company will include the wind PTC in the 2021 IRP. However, Staff disagrees that it was being inconsistent in its Final Comments regarding the addition of this resource. Staff's intent to encourage use of the PTC was not about Idaho Power pursuing wind to be long on the market or to pursue an economic opportunity. Staff simply believes that all available and appropriate data should be

[98] LC 74, Idaho Power's Final Comments, page 53.
[99] LC 74, Idaho Power's Final Comments, page 49.
[100] LC 74, Idaho Power's Final Comments, page 50.

updated and used in the IRP, and the PTC fits within this universe of options. Idaho Power has argued in its IRP that it will have a resource need in 2026. Staff is not opposed to prudently incurred resource acquisition, and modeling wind correctly would be part of a prudently considered portfolio.

Regarding storage, Staff appreciates that the Company will raise the threshold for hybrid resources in the 2021 IRP.

Finally, while Staff can understand the use of a “surrogate” as a proxy for a flexible resource, Staff encourages the Company to carefully consider the fitness of this choice. A gas peaker is not an emerging technology, it relies on a well-established source of fuel and pipeline network, it is a more well-established technology, and the costs are better understood despite fluctuations in market prices for gas. Despite the fact that alternative technologies may decline in costs as time goes on, the risk of misapplying assumptions for one resource to another must also be considered. The selection of the gas resources is far outside the scope of the Action Plan window, so there is still time to investigate the optimal choice for a technology that will align with Idaho Power’s Clean by 2045 goal.

Recommendations for the 2021 IRP:

- **Allow an exemption to Order No. 16-362.**
- **Perform the Company’s approved capacity factor approximation method using all the new data that has become available.**
- **Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.**
- **Model the PTC for wind to the extent it is technically achievable by the Company.**
- **Revise its Wyoming cost inputs to include more reasonable cost assumptions.**

Climate Change Risk Report

In the 2017 IRP, Staff asked the Company to commission a report for the next IRP to assess the risks and uncertainties associated with climate change to Idaho Power and its customers. The Commission Order acknowledging the IRP adopted Staff’s recommendation.[101] In the 2019 IRP, while the Company did briefly address this issue by stating that it performed a climate change analysis using data from various sources to analyze water availability in the Pacific Northwest under various climate change scenarios, Staff could not identify a unifying report specifically meeting the Commission's Order. Staff asked the Company to explain how it complied with the Commission's directive to develop this report, and Idaho Power pointed to analysis it had done to examine the effects of climate change on its hydropower system and that the Company was in the process of developing a "more comprehensive internal plan."[102] This appeared to include a Sustainability Report in addition to Idaho Power's Climate Change Adaptation Plan. It is unclear whether any of these reports were meant to comply with Commission Order No. 18-176. Staff recommends that the Company provide a standalone report to serve as the Climate Change Risk Report that accompanies its next IRP.

Since 2018, when Order No.18-176 was issued, Staff notes that there has been a great deal of work to refine and improve how companies assess climate risk. Staff suggests looking to approaches in other forums on how to assess and disclose climate-related risk. [103] The Company should consider including a description of the Company's process for identifying, assessing, and managing climate-related risks and how it integrates these risks into its overall risk management. Further, regarding climate risk evaluation and assessment in planning, financial reporting, and other business practices, Staff suggests that the Company consider the following elements in its report: [104]

1. Describe the metrics and/or methods that the utility uses to evaluate climate-related financial and operational risks covering investments in and returns from generation;
2. Describe the methods used in considering financial and operational risk mitigation from non-generation activities that make the system more flexible and efficient, (such as investments in smart networks and customer solutions); and
3. Indicate which metrics and/or methods are used to track climate-related transition risks, physical risks, and catastrophic or "tail" risks.

Staff is very interested in further discussions on climate risk planning best practices and plans to engage with stakeholders to have robust conversations on this topic as part of its IRP related response to EO 20-04.

---

[101] Order No. 18-176 at 17.
[102] LC 74, Idaho Power Reply Comments, page 76.
[103] See the TCFD Electric Utilities Preparer Forum paper, *Disclosure in a time of transition: Climate related financial disclosure and the opportunity for the electric utilities sector. Accessible at https://docs.wbcsd.org/2019/07/WBCSD_TCFD_Electric_Utilities_Preparer_Forum.pdf.*
[104] *Ibid.*

Further, in response to EO 20-04, Staff plans to launch a series of workshops in 2021 to explore additional, and in some cases more granular portfolio emissions data in the next IRP. Staff looks forward to working with the Company to identify the best ways to uncover and understand pathways to meet GHG emission reduction targets with this additional information. Staff hopes to see at least some of the following items included in the next IRP:

- A model and description of the necessary changes to the IRP Preferred Portfolio operations and resource mix to meet various emissions targets (both the Company's and where different, those in EO 20-04) and to reliably serve load.
- If hourly dispatch and emissions data are available, production of a 12 x 24 matrix of gross (not net) GHG emissions. If not available, a description of the challenges to producing a 12 x 24 matrix of gross (not net) GHG emissions using select portfolios from the IRP in select years.
- Estimates of the Company's carbon intensity per customer in select years.
- Load duration curves for select years that detail the estimated 8,760 hourly operation costs and emissions.
- Emissions associated with annual "sales for resale" from fossil fuel sources.

Recommendation for the 2021 IRP:

- **The Company should produce the Climate Change Risk Report referenced in the 2017 IRP acknowledgment order and include it in the next IRP.**

Waiver

In its Final Comments, Idaho Power requested a waiver from IRP 5 Guideline 3(f), which requires an annual update to the IRP. The reasoning behind the request is that the Company believes it will have filed the 2021 IRP before the annual update deadline, which will be one year after the Second Amended 2019 IRP acknowledgment.

Given the timing of when the Company anticipates filing its IRP, Staff is not opposed to recommending a waiver as long as the Company actually files its IRP within one year of the acknowledgment. If the Company believes there will be any delay to the filing, the Company should file an Update to the IRP.

Staff Recommendation:

- **Waive the IRP Update unless the Company is unable to file its IRP before the annual update deadline.**

Conclusion

Staff appreciates the hard work of Idaho Power and each of the stakeholders participating in this case. Staff has presented a series of recommendations above. Below is a summary of Staff's recommendations in this proceeding.

1. Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition. (2020-2022)
   Recommendation: Acknowledge

   Additional Recommendation: Provide a reliability impact analysis for Jim Bridger retirement.

2. Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP. (2020-2022)
   Recommendation: Acknowledge

3. Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s). (2020-2026)
   Recommendation: Acknowledge

4. Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. (2020-2026)
   Recommendation: Acknowledge

   Additional Recommendations:
   - Continue to include the 20 percent cost contingency for B2H in the 2021 IRP.
   - Update B2H costs prior to creating new portfolios in the 2021 IRP.
   - Model cost risk as it relates to a change in ownership arrangement in the 2021 cycle. This could be in the form of a series of sensitivities, where the

Company continues to own 21 percent of the line and retail customers are held harmless, and introduce additional costs to customers based on a range of capital risks.

- Dedicate time in a 2021 IRPAC meeting addressing the issue of B2H cost risk as a result of new ownership structures. In the meeting, the Company should address the questions raised below:
    - What are the specifics of the ownership arrangements the Company is considering?
    - What is the risk that costs would increase under new arrangements?
    - What sort of capital risk would Idaho Power be taking on by assuming additional ownership?
    - How would these risks impact the Preferred Portfolio in an IRP?
    - How is the Company going to model this risk in the 2021 IRP cycle?
    - What would be the specific accounting authorizations needed for such an arrangement?
    - What actions will Idaho Power take to minimize supply chain risk?
    - What would be the specific types of contracts needed for such an arrangement?
    - Would a change in partnership or service arrangement affect the in-service date of B2H?
    - Is there still a possibility that another third party could assume ownership?

5. Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units. (2020)
   Recommendation: Not Acknowledge due to timing

   Additional Recommendation: File the results of each of the VER studies with the Commission once they are complete and notify the LC 74 service list.

6. Exit Boardman December 31, 2020. (2020)
   Recommendation: Not Acknowledge due to timing

7. Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized. (2020)
   Recommendation: Not Acknowledge due to timing

   Additional Recommendation: Update the Commission as soon as it knows the outcome of PacifiCorp’s negotiation with the Wyoming DEQ regarding continued use of Jim Bridger Units 1 and 2 without SCR investments.

8. Conduct a VER Integration Study. (2020)
Recommendation: Not Acknowledge due to timing

9. Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2. (2020-2021)
Recommendation: Acknowledge

10. Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units. (2021-2022)
Recommendation: Acknowledge

11. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022. (2022)
Recommendation: Acknowledge

12. Jackpot Solar 120 MW on-line December 2022. (2022)
Recommendation: Not Acknowledge

13. Exit Valmy Unit 2 by December 31, 2022.
Recommendation: Not Acknowledge

    Additional Recommendation: Change the Action Item to include a Valmy Retirement in 2025 until the Company has completed the appropriate analysis to show 2022 is an optimal retirement date.

14. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H). (2026)
Recommendation: Acknowledge

Following is a list of additional Staff Recommendations based on analysis in this Staff Report.

Additional Staff Recommendations

- Report qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.
- Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.

- Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.
- Review all energy efficiency measures piloted by Energy Trust in 2018-2020 and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. The Company should share the status of its review at an Energy Efficiency Advisory Group meeting in 2021 and as a report in the 2021 IRP.
- Use a metric like the Akaike Information Criterion to confirm that indicator variables are not causing model overfitting.
- Present a plan for cross-validation or similar to check whether ARIMA models are likely to reduce load forecast error in the next IRP and check robustness of Idaho Power's load forecasting model.
- Address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.
- Present to Commissioners the impact of COVID-19 on load.
- The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.
- Provide an update on the Oregon Residential Time-of-Day Pilot Plan including number of participants, total cost of the pilot since its 2019 launch, and peak capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the Smart Grid Report will be suspended with the Commission approval of DSP guidelines.
- Work with Staff and stakeholders to develop a new modeling approach suitable for behavior-based DR programs that reflects such programs' typical lower costs and less certain results.
- Perform sensitivity analysis in its 2021 IRP pertaining to wind replacement assumptions to evaluate the impact on resource planning.
- Allow an exemption to Order No. 16-362.

- Perform the Company's approved capacity factor approximation method using all the new data that has become available.
- Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.
- Model the PTC for wind to the extent it is technically achievable by the Company.
- Revise its Wyoming cost inputs to include more reasonable cost assumptions.
- The Company should produce the Climate Change Risk Report referenced in the 2017 IRP acknowledgment order and include it in the next IRP.
- Waive the IRP Update unless the Company is unable to file its IRP before the annual update deadline.

PROPOSED COMMISSION MOTION:

Acknowledge Idaho Power's 2019 IRP in part and decline to acknowledge in part Idaho Power's 2019 Integrated Resource Action Plan. Staff recommends certain action and additional requirements on pages 52-56 of this Staff Report.

LC 74 – Idaho Power 2019 Integrated Resource Plan.