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February 5, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket LC 74 – Idaho Power Company's 2019 Integrated Resource Plan ("IRP")

Attention Filing Center:

Attached for filing in the above-captioned docket is Idaho Power Company's Final Comments.

Please contact this office with any questions.

Sincerely,

/s/ Cheyenne Aguilera

Cheyenne Aguilera
Office Manager

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

In the Matter of IDAHO POWER COMPANY'S Second Amended 2019 Integrated Resource Plan.	**IDAHO POWER COMPANY'S FINAL COMMENTS**

February 5, 2021

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I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Final Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the final comments of Commission Staff ("Staff"), the Oregon Citizens' Utility Board ("CUB"), the STOP B2H Coalition ("STOP B2H"), Renewable Northwest, and the Renewable Energy Coalition ("REC") concerning Idaho Power's *Second Amended 2019 Integrated Resource Plan* ("IRP").

The *Second Amended 2019 IRP* continues to demonstrate a clear, cost-effective, and reliable trajectory toward Idaho Power's clean energy future. This commitment is reflected in the Company's three key short-term (2020-2026) action plan ("Action Plan") items: (1) adding 120 megawatts ("MW") of new solar generation by 2022; (2) exiting from four coal-fired units by year-end 2022, and from five of the Company's seven coal-fired units by year-end 2026; and (3) completing the Boardman-to-Hemingway ("B2H") transmission line by 2026. B2H, in particular, will be a crucial carbon-free and cost-effective supply-side resource that supports renewables and enables the Company's transition away from coal. As recently detailed in an extensive new report by the Americans for a Clean Energy Grid,[1] and echoed by multiple former Federal Energy Regulatory Commission ("FERC") chairs and commissioners,[2] substantial new regional transmission is essential to achieve a truly clean energy future.[3]

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[1] Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 24 (Jan. 2021) (noting that almost 90 percent of the 734 gigawatts of proposed generators waiting in interconnection queues in 2019 were renewable and storage resources).

[2] Jeff St. John, GreenTech Media, "Report Calls for a Ground-Up Overhaul of Federal Transmission Grid Policy" (Jan. 28, 2021) ("There is no climate plan that is serious if it does not anticipate a significant regional transmission upgrade[.]") (quoting Pat Wood III, FERC chair 2001-2005); *id.* (describing the need for new transmission investments: "Not only yes, but hell yes.") (quoting James Hoecker, FERC chair 1997-2001).

[3] *See, e.g.,* Jeff St. John, GreenTech Media, "Transmission Emerging as Major Stumbling Block for State Renewable Targets" (Jan. 15, 2020) ("One of the key takeaways [from the third-party report] is the mismatch between where renewable supply is versus where it's going to be needed to meet the various mandates and renewables goals being made in states and regions[.]") (quoting Larry

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Parties to this proceeding largely support the Company's Action Plan, with the exception of STOP B2H's opposition to B2H. With the benefit of Staff and stakeholder feedback, Idaho Power has diligently worked to improve its modeling process in this case, resulting in more efficient, transparent, and replicable resource planning. Throughout this process, the Company's analysis has clearly and consistently supported the development of additional solar generation, the transition away from coal, and the construction of B2H as the least-cost, least-risk means to serve customers.

The primary goal of an IRP is to select the least-cost, least-risk portfolio for a utility and its customers.[4] Idaho Power's *Second Amended 2019 IRP* meets and exceeds this standard. It provides a robust analysis of the long-term planning and resource decisions needed to affordably and reliably serve customers, and clearly supports the Company's near-term action items. Idaho Power therefore respectfully requests that the Commission acknowledge this *Second Amended 2019 IRP* and the Company's Action Plan.

II. STANDARD FOR ACKNOWLEDGMENT

Idaho Power's IRP must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a resource portfolio with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[5] As noted above, the primary goal of an

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Gasteiger, former FERC Deputy Director); *see also* Energy Strategies, LLC, *Western Flexibility Assessment: Investigating the West's Changing Resource Mix and the Implications for System Flexibility* at 9 (Dec. 10, 2019) ("As the resource portfolio evolves into the 2030s, the need for transmission becomes more obvious and resources face transmission constraints.").

[4] *In the Matter of Pub. Util. Comm'n of Or. Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 5 (Jan. 8, 2007) (Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").

[5] *In the Matter of Idaho Power Company, 2013 Integrated Resource Plan*, Docket LC 58, Order No. 14-253 at 1 (July 8, 2014).

IRP is to select the least-cost, least-risk portfolio for the utility and its customers.[6] To meet this goal, the Commission requires the IRP to analyze a planning horizon of "at least 20 years."[7] The Commission's guidelines also require the IRP to include an action plan that identifies the specific resource activities the utility intends to undertake in the next two to four years.[8] When adopting the IRP guidelines, the Commission noted that, "in an IRP, the Commission looks at the reasonableness of individual actions in the context of the entire plan."[9]

When acknowledging an IRP, the Commission acknowledges only the action plan and does not acknowledge action items planned to occur more than four years in the future.[10] Commission acknowledgment confirms that the action plan satisfies the procedural and substantive requirements of the Commission's IRP guidelines and is "reasonable based on the information available at that time."[11]

Importantly, the Commission has repeatedly "reaffirm[ed] [its] long-standing view that decisions made in IRP proceedings do not constitute ratemaking"[12] and, further, "[d]ecisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding."[13]

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[6] Order No. 07-002 at 5 (Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").
[7] Order No. 07-002 at 5.
[8] Order No. 07-002 at 12 (Guideline 4(n)).
[9] Order No. 07-002 at 25.
[10] Order No. 14-253 at 12; *In the Matter of Idaho Power Company, 2011 Integrated Resource Plan*, Docket No. LC 53, Order No. 12-177 at 6 (May 21, 2012) ("We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items . . .").
[11] Order No. 14-253 at 1.
[12] Order No. 14-253 at 1.
[13] Order No. 14-253 at 1.

III. BOARDMAN TO HEMINGWAY

A. Boardman to Hemingway Partnership Risks

In the *Second Amended 2019 IRP*, Idaho Power reported on the status of its negotiations with its B2H project permitting co-participants, PacifiCorp and Bonneville Power Administration ("BPA"). The project permitting co-participants are actively discussing potential arrangements and associated agreements for ownership and cost responsibility for B2H.[14] In letters sent to the Commission on July 1 and July 31, 2020, Idaho Power provided updates on the Company's discussions with BPA, in particular.[15] As the Company explained, it is exploring a possible change in ownership structure with BPA, whereby Idaho Power would acquire BPA's 24 percent ownership share of B2H and provide transmission service to BPA's southeast Idaho customers; in return, BPA and/or its customers would, over time, pay for its respective usage of B2H by recompensing Idaho Power for BPA's share in the transmission line.

The primary purpose of these update letters was to inform the Commission and stakeholders that BPA and Idaho Power are considering transitioning BPA's B2H ownership into a transmission service-based stake in the project. To be clear, the Company's description of this potential ownership arrangement was not an announcement of BPA pulling out of negotiations for the project. BPA, PacifiCorp, and Idaho Power each remain committed to permitting the project and continue to actively fund their share of costs associated with the development of B2H.

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[14] Docket LC 74, Idaho Power Company's Amended 2019 IRP Application, Attach. 1 at 19 (hereinafter "Second Amended 2019 IRP") (Oct. 2, 2020) ("The company's assumption of BPA's contemplated 24 percent ownership would be offset by the transmission wheeling service to BPA and/or its customers.").

[15] Docket LC 74, Idaho Power's Motion to Suspend Procedural Schedule and Update Regarding Boardman to Hemingway Transmission Line Project at 5-6 (July 1, 2020); Docket LC 74, Idaho Power's Update and Request for Extension of Two Months to Complete Extended Analysis at 3-4 (July 31, 2020).

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One option for BPA's participation may involve repayment through transmission service, with BPA and/or its customers paying for transmission wheeling under the provisions of Idaho Power's Open Access Transmission Tariff ("OATT") and entering into a transmission service agreement.[16] Under this possible arrangement, BPA and/or its customers' OATT payments would, over time, provide recovery of Idaho Power's transmission revenue requirement associated with BPA's respective usage of B2H. Any change in ownership arrangements does not change Idaho Power's need for B2H capacity.[17]

BPA and Idaho Power remain in active dialog over the ownership arrangement, and Idaho Power is also engaged with PacifiCorp in the larger B2H discussions. Beyond the previously provided updates, described above, Idaho Power has no new substantive reports to provide—though this does not mean that no progress is being made. On the contrary, the parties are continuing discussions in earnest. Idaho Power anticipates that the ownership arrangements will be finalized by the time the Company files its 2021 IRP. However, for the reasons stated below, Idaho Power does not believe that the implications of these ownership arrangements materially impact the Preferred Portfolio results or Action Items in the *Second Amended 2019 IRP*.

1. Idaho Power's B2H Partners Remain Committed to the Project.

While Staff does not directly contest the commitment of other B2H co-participants to the future development of B2H, Staff questions whether there are other entities that may be interested in joining in the B2H project—thus further reducing project costs.[18] While Idaho Power believes that speculation on additional project participants is unnecessary given the ongoing discussions with the current co-participants in the project, the Company observes that the demand for and value of the capacity offered by B2H is increasing over time. Several

[16] Second Amended 2019 IRP, Appendix D at 59.
[17] Second Amended 2019 IRP at 19.
[18] Staff's Final Comments at 36 (asking if a third party may step in for BPA) (Jan. 8, 2021).

utilities have expressed interest in B2H—including Puget Sound Energy, which recently modeled B2H in its draft IRP.[19] B2H has capacity that is currently unallocated, meaning that there is potential for another party to step in and participate, which would reduce the costs for all parties involved. The Company is confident that, in the event it does not reach final terms with BPA, there is sufficient demand for the project to account for the line's total capacity.

Staff has also expressed interest in understanding whether a change in ownership or service arrangements would affect B2H's in-service date.[20] It would not. B2H's 2026 in-service date is driven by a capacity need that arises for Idaho Power in that year. The Company has shown through robust modeling in this IRP that B2H remains the least-cost resource to meet an identified capacity need beginning in 2026.[21]

STOP B2H voices concerns regarding the status of negotiations with the B2H co-participants—requesting a detailed analysis of any changes in ownership and financing arrangements, and questioning PacifiCorp's commitment.[22] As noted above, because negotiations with BPA are not finalized, it is premature for the Company to incorporate changes to the ownership that, at this stage, remain hypothetical. But regardless of the ultimate ownership stakes, the Company will not agree to arrangements that shift cost risk to its retail customers without a corresponding increase in benefits—and, as such, the Company does not expect material changes to its IRP analysis stemming from BPA-related B2H ownership arrangements.

Regarding PacifiCorp's commitment to B2H, STOP B2H misunderstands PacifiCorp's recent filings. STOP B2H points to PacifiCorp's discussion of B2H in that company's 2019 IRP, in which PacifiCorp stated that it remains committed to the permitting of the project and

[19] Wash. Utils. & Transp. Comm'n, Dockets UE-200304 and UG-200305, 2021 Draft PSE Integrated Resource Plan at Ch. 5-36 (Jan. 4, 2021).
[20] Staff's Final Comments at 34-36 (Jan. 8, 2021).
[21] Second Amended 2019 IRP at 6.
[22] STOP B2H's Final Comments at 7-12 (Jan. 8, 2021).

will continue to evaluate the benefits of the project throughout project development activities, including moving forward with preliminary construction.[23] STOP B2H also points to PacifiCorp's explanation in response to a Staff DR submitted in PacifiCorp's 2019 IRP.[24] In that DR response, PacifiCorp explained that it did not include B2H in any of its new transmission options in System Optimizer. While Idaho Power cannot speak to the decision-making of another utility in its modeling process, PacifiCorp's own final comments in the 2019 IRP make clear that the treatment of transmission in its modeling is a technical question—not an issue of commitment to B2H as a least-cost, least-risk resource.[25]

Similarly, STOP B2H suggests that PacifiCorp is not committed to the B2H project by pointing to an old PacifiCorp Gateway West project called Hemingway-to-Captain Jack ("Captain Jack") as a B2H alternative—one which PacifiCorp is purportedly exploring.[26] STOP B2H appears to misunderstand the referenced footnote in PacifiCorp's IRP, which states: "The Boardman-to-Hemingway project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack)."[27] Idaho Power understands that the Captain Jack project was pursued by PacifiCorp *over a decade ago*; as far as Idaho Power is aware, the Captain Jack project was long since abandoned.

Idaho Power believes that PacifiCorp remains committed to its longstanding plan to assume a 55 percent ownership share in B2H. And while the details of the arrangements with all parties have yet to be finalized, the Company anticipates that PacifiCorp will continue to

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[23] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket LC 70, PacifiCorp 2019 IRP at 25, 77-79 (Oct. 18, 2019).
[24] STOP B2H's Final Comments at 8-9.
[25] LC 70, PacifiCorp's Final Comments at 42 (Apr. 1, 2020) (responding to Staff's comments regarding why the B2H transmission line "cannot be modeled endogenously as a simple connector between the Hemingway bubble and the [BPA] bubble in the IRP topology").
[26] STOP B2H's Final Comments at 7, 12.
[27] LC 70, PacifiCorp's 2019 IRP at 83.

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support full participation in B2H going forward. Development of B2H remains part of PacifiCorp's Action Plan in its most recent IRP.[28]

2. Idaho Power Commits to Securing the Best B2H Partnership Arrangement for Idaho Power's Customers.

Staff expresses concern that, due to delays in the 2019 IRP process, the Preferred Portfolio may not provide an accurate reflection of current costs and risks to Idaho Power's customers, with respect to B2H.[29] Staff asks the Company to address capital cost or increased cost risk as a result of new participant arrangements, and states that the Company must model ownership-related cost risks in the 2021 IRP.[30]

First, Idaho Power recognizes that the timing of the 2019 IRP has been unusual, and appreciates the Commission's, Staff's, and other parties' support for the Company's ongoing efforts to ensure that this IRP is both rigorous and accurate. However, as Staff also recognizes, it would not have been practicable for Idaho Power to refresh only some data in this IRP cycle.[31] Isolated updates without a comprehensive refresh would merely distort the Company's results—which remain tied to the 2019 long-term planning process.

Second, any changes to the ownership structure for B2H are immaterial for this IRP cycle, as the hypothetical arrangements contemplated to date would not increase the net costs associated with the project for Idaho Power's customers relative to amounts already considered in the Second Amended 2019 IRP analysis. Idaho Power has committed that it will not reach any deal with BPA that would harm retail customers or the Company's shareholders, thus eliminating any cost increases due to partnership changes that are not associated with increases in benefits for retail customers. Given that the Company's Preferred Portfolio is designed to reflect the least-cost, least-risk option in the long-term interests of

[28] LC 70, PacifiCorp's Reply Comments at 6 (Feb. 5, 2020).
[29] Staff's Final Comments at 37.
[30] Staff's Final Comments at 37.
[31] Staff's Final Comments at 36.

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customers, Idaho Power appropriately would not include cost factors that are irrelevant to customers in the IRP modeling process.

Third, the Company does not expect that a change in ownership arrangements will negatively impact the Company's ability to raise capital to finance its operations. While BPA and Idaho Power are exploring different financing arrangements, the Company is familiar with raising capital to fund major projects and ongoing operations. For example, the Langley Gulch power plant exceeded $400 million,[32] and Idaho Power's 2020 capital budget was forecast to be between $300-310 million.[33]

If Idaho Power contributes toward assumption of BPA's originally contemplated 24 percent share of B2H, these amounts would be subject to repayment through transmission service. The Company would enter such an arrangement *only* with comprehensive assurance that any risk associated with the additional investment would be mitigated contractually. Therefore, although the total B2H project investment could be higher, the project cost attributable to Idaho Power's retail customers—and therefore used for modeling least-cost/least-risk resources in the IRP—would remain at 21 percent unless or until the changed circumstances and associated analysis justifies a modification to benefit customers.[34] This 21 percent is consistent with the ownership share the Company modeled in the 2019 IRP.

STOP B2H argues that, until Idaho Power finalizes all ownership arrangements, the Commission should not acknowledge the *Second Amended 2019 IRP*.[35] STOP B2H further recommends that the Commission direct Idaho Power to complete funding and financing

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[32] *In the Matter of Idaho Power Co. Gen. Rate Revision Application for Authority to include the Langley Power Plant Investment in Rate Base*, Docket UE 248, Direct Testimony of Lisa A. Grow, Idaho Power/200, Grow/11 (March 9, 2012).
[33] Idaho Power's 2019 10-K estimate for 2020 Capital Expenditures.
[34] For instance, if a future IRP analysis concluded that Idaho Power's customers would benefit from a larger percentage ownership share in B2H and the Company can obtain that percentage, then costs might increase to reflect the capacity actually used to serve customers.
[35] STOP B2H's Final Comments at 11.

arrangements before the next IRP begins so that it can develop a new suite of portfolios with contractually verifiable costs, thus allowing the analysis to be based on "hard numbers."[36] The Commission should reject these recommendations.

First, STOP B2H's proposal assumes a degree of granularity and certainty in project costs that is neither reasonable nor feasible for long-term resource planning—and which is not demanded for other resources in the IRP process. As discussed in more detail below, Idaho Power has included a substantial 20 percent contingency as a buffer for B2H costs, thus allowing for considerable leeway in modeling relative portfolio costs and benefits. Any long-term forecast of project costs will inevitably carry some degree of risk with respect to cost fluctuations.[37]

Second, making the Company's entire 2021 IRP contingent on the timing of B2H negotiations is unreasonable and impractical. While B2H has been a very important component of each of the Company's past IRPs, it is only one component and it should not hold up an entire process. As with any element in its IRP, the Company will provide updated B2H information as an input into the process as soon as practicable.

Third, and as noted above, there is no need to condition the Company's ability to move forward with prudent resource planning on cementing specific contractual arrangements. Certainly, Idaho Power looks forward to finalizing ownership and cost responsibility arrangements for B2H so that it can provide an updated analysis in its next IRP. That said, the Company has already determined that B2H costs would need to increase significantly beyond the 20 percent contingency before it is no longer least-cost and least-risk. And based

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[36] STOP B2H's Final Comments at 11.

[37] *In the Matter of the Application of Northwest Natural for a General Rate Revision*, Docket UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) (stating that "all construction projects inevitably involve some difficulties").

on the direction of current negotiations, the Company hopes to further increase the benefits of B2H to customers beyond those contemplated in the current IRP.

Finally, the Company reiterates its commitment that an ownership change to provide transmission service to BPA will not increase the net costs for Idaho Power's retail customers without associated increases in benefits. Therefore, these ownership arrangements should not impact the Commission's ability to reasonably assess the potential economic and operational benefits of B2H in this IRP. As a result, there is plainly enough certainty that B2H is a reasonable part of the Company's Preferred Portfolio for the Commission to acknowledge the B2H Action Items, and the IRP, based on the analysis that has been provided.

3. <u>Idaho Power's 2021 IRP Will Include Modeling of B2H Partnership Costs and Risks.</u>

The Company intends to file its 2021 IRP before the end of 2021. As part of this 2021 IRP, Staff states that the Company must model cost risk as it relates to a change in ownership in B2H, and suggests that this could be in the form of a series of sensitivities—*i.e.*, identifying additional costs to customers based on a range of capital risks.[38]

The Company understands Staff's desire to have a better understanding of the potential impacts on Idaho Power's customers of any changes to the ownership and cost responsibility arrangements for B2H, and the Company further agrees that the 2021 IRP will be the appropriate context for that analysis. During the development of the 2021 IRP, the Company anticipates that it will have finalized the details of the ownership and cost responsibility arrangements for B2H. To that end, the Company expects to be able to provide a more detailed analysis of any associated cost and risk impacts in the 2021 IRP.

The Company agrees that any known changes to the B2H co-participant arrangement with BPA and PacifiCorp will be included as an input to the 2021 IRP and intends to make every effort to finalize and release the terms of an arrangement as soon as possible. Once a

[38] Staff's Final Comments at 37.

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framework of terms is agreed to, the Company looks forward to more detailed discussions concerning the agreed-upon arrangement.

B. Modeling B2H Costs

The B2H cost estimate included in the *Second Amended 2019 IRP* was developed in 2018 as a key IRP input, and includes a 20 percent contingency as part of the estimate.[39] Other resources evaluated in the IRP had zero contingency included in their estimates. This 20 percent contingency for B2H is unique and provides a significant project buffer.

STOP B2H requests that Idaho Power perform a tipping point analysis to determine how much more cost the Company can absorb until another portfolio becomes least-cost and least-risk.[40] In the 2019 IRP, Idaho Power estimated that the Company's share of the B2H project would total $313 million, including contingency and allowance for funds used during construction. Once levelized and converted to a present value, the total B2H net present value ("NPV") cost is approximately $108 million.[41] This $108 million cost is part of the total cost of all portfolios that include the B2H project. Removing the 20 percent contingency would reduce this $108 million by about 20 percent and reduce the cost of all B2H portfolios by that amount. Conversely, increasing the cost contingency would similarly increase the cost of B2H portfolios.

With this understanding—and focusing on Table 9.7 in the *Second Amended 2019 IRP*, specifically the Planning Gas-Planning Carbon ("PGPC") column—the best portfolio including B2H is PGPC B2H (1) and the best portfolio without B2H is PGPC (2). The difference between these portfolios is approximately $35 million on an NPV basis. That indicates B2H costs could increase another 30-35 percent above the current 20 percent contingency already

[39] Idaho Power provided a discussion of B2H costs in the Second Amended 2019 IRP, Appendix D at 40. The Company also provided a discussion within the IRP Review Report starting on page 37.
[40] STOP B2H's Final Comments at 7.
[41] Second Amended 2019 IRP, Appendix D at 53.

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included before a non-B2H portfolio would be more cost-effective. This simple analysis assumes only cost increases with no corresponding value increases. If additional capacity were associated with cost increases, additional AURORA modeling would be required.

In preparation for the 2021 IRP, the Company is currently working with an engineering consultant to revise the B2H estimate for the 2021 IRP. Idaho Power plans to include a breakdown of the cost estimate, including the contingency component, in the 2021 IRP. Preliminary results suggest that the 2021 cost estimate will be less than the 2018 estimate. The Company has not determined whether it is appropriate to maintain a large contingency for B2H given that no contingency is included for other resources being evaluated in the 2021 IRP. Per Staff's recommendation, the Company will incorporate a cost-sensitivity analysis in the 2021 IRP.[42]

C. B2H Capacity Acknowledged in Idaho Power's 2017 IRP

In the *Second Amended 2019 IRP*, the Company modeled B2H as 500 MW of summer capacity and 200 MW of winter capacity (on average, such a capacity arrangement results in Idaho Power's 21 percent share).[43] This amount is consistent with the B2H Permit Funding Agreement and with the Company's approach in the 2017 IRP. In this proceeding, STOP B2H asks the Commission to retrospectively "clarify what capacity measure" the Commission acknowledged in the 2017 IRP.[44]

In Order No. 18-176, the Commission acknowledged the inclusion of B2H in Idaho Power's Short-Term Action Plan.[45] Specifically, the Commission acknowledged the following two Action Items:

[42] Staff's Final Comments at 37.
[43] Second Amended 2019 IRP, Appendix D at 28.
[44] STOP B2H's Final Comments at 16.
[45] *In the Matter of Idaho Power Company, 2017 Integrated Resource Plan*, Docket LC 68, Order No. 18-176 at 7 (May 23, 2018).

> **Action Item 5**: Conduct ongoing permitting, planning studies, and regulatory filings for the B2H transmission line and conduct preliminary construction activities, acquire long lead materials (2017-2020).

> **Action Item 6**: Construct the B2H Project (2018-2026).[46]

B2H is described throughout the 2017 IRP and the Commission's Order as a 500 kV transmission line,[47] meaning that the Commission's order must be read as an unequivocal acknowledgment of the Company's plan to permit and construct a transmission line *of that size*.

As the Commission is aware, Idaho Power has relied on the acknowledgment of its 2017 IRP in its Application for Site Certificate with the Energy Facility Siting Council ("EFSC"), which allows Idaho Power to demonstrate a "need" for the facility with an acknowledgement of an IRP with the capacity of the facility in its Short-Term Action Plan.[48] In the EFSC proceeding, STOP B2H has argued that EFSC cannot rely on the Commission's previous acknowledgement of the B2H Action Items because, in its view, the Commission has acknowledged only 21 percent of the capacity of the transmission line. Idaho Power has opposed that argument, pointing out that the Commission's acknowledgement is not for a specific portion of the capacity of the line, but rather of the Company's intended actions necessary to construct the line as a whole.[49] This dispute over the meaning of the Commission's acknowledgment will be one of the issues addressed in the EFSC contested case.

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[46] Order No. 18-176 at 9.
[47] Order No. 18-176 at 5.
[48] Energy Facility Siting Council, Idaho Power Company's Application for Site Certificate, Exhibit N, Attachment N-10 (Sept. 28, 2018).
[49] Likewise, the Oregon Department of Energy ("ODOE") has confirmed its own view that the Commission's acknowledgement of the 500 kV line satisfies EFSC's "need" standard. ODOE, Boardman to Hemingway Transmission Line Application for Site Certificate, Proposed Order at 595-596 (July 2, 2020).

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STOP B2H is now asking the Commission to parse and re-interpret its acknowledgement of the 2017 IRP B2H Action Items to "clarify" that the Commission's acknowledgment was limited to Idaho Power's 21 percent share of B2H, not for the line as a whole.[50] STOP B2H asks the Commission whether its own view is correct or whether the Commission acknowledgement was for a 500 kV transmission line "without partners."[51] In posing this false choice, STOP B2H misunderstands the meaning of the Commission acknowledgment, as well as the realities of constructing a transmission line.

As a practical matter, it would be impossible for Idaho Power to utilize a 21 percent share of B2H unless 100 percent of the line is built. This is a matter of logic, not interpretational nuance. Therefore, to the extent that the Commission acknowledged the Company's intent to proceed with "preliminary construction activities" and to "construct the B2H Project," this acknowledgement necessarily understood that a line must be constructed in whole—not in percentage increments. While Idaho Power believes that no clarification of the Commission's 2017 IRP order is necessary, if the Commission is inclined to respond to STOP B2H's contentions, then the Commission should make clear that Order No. 18-176 acknowledged Idaho Power's decision to proceed with constructing B2H as a whole, with the understanding that Idaho Power has, on average, a 21 percent interest in the line's ultimate capacity.

Separately, and as noted above, the Commission's acknowledgment of the 2017 IRP B2H Action Items confirmed the reasonableness of the Company's plan to construct a 500 kV transmission line—***with partners***. STOP B2H is correct that Idaho Power has not demonstrated its own need for the entire capacity of the 500 kV line—but that is not what is required to earn acknowledgment of its Action Items. On the contrary, the Company's analysis

[50] STOP B2H's Final Comments at 16-17.
[51] STOP B2H's Final Comments at 16.

has demonstrated that the least-cost, least-risk approach to meeting its capacity needs is to construct a 500 kV line with other parties that will support the project to meet their own capacity needs. In fact, Idaho Power's analysis in support of the 2017 IRP demonstrated that constructing a 500 kV line with partners is considerably less costly than constructing a smaller transmission line to meet its individualized needs,[52] and therefore it is not clear that the Commission could or would have acknowledged an Action Plan to acquire a transmission resource designed to meet just Idaho Power's own capacity needs. Clearly, the Commission has acknowledged the Company's Action Plan to permit and construct the 500 kV line, with the understanding that Idaho Power would not use the whole line independently.

Finally, to be clear, while Idaho Power's anticipated cost responsibility is for 21 percent, the Company's practical use of the line will exceed that percentage, particularly during the summer months. During those months of Idaho Power's peak capacity need, B2H is intended to provide the Company with an additional 500 MW of West-to-East capacity—which represents approximately 50 percent of the total capacity of B2H in the West-to-East direction.[53] Indeed, Idaho Power's ability to rely on B2H for West-to-East capacity during the summer, in partnership with other entities seeking greater East-to-West capacity, highlights the benefits of the proposed co-participant arrangement for B2H. Thus, even if the Commission's 2017 IRP acknowledgement had been limited to Idaho Power's individual need for capacity on B2H to serve its own customers, this need would exceed a 21 percent interest in the 500 kV size of the line.

[52] LC 68, Idaho Power's 2017 IRP, Appendix D, B2H Supplement at 63 (hereinafter "2017 IRP, Appendix D") (Dec. 8, 2017) (showing different transmission options considered). Idaho Power also provided, in response to Staff Data Request 118 in that docket, a cost comparison relative to the size of the different transmission options that the Company considered. B2H was the most cost-effective solution on a per-MW basis, as compared to upgrading existing 230 kV lines.
[53] 2017 IRP, Appendix D at 28.

In discussing its acknowledgment of the 2017 IRP, the Commission emphasized that the acknowledgement of B2H was based on its own requirements—and specifically noted that its order did not interpret standards of any other state or federal agency.[54] Consistent with this approach, the Commission should resist STOP B2H's invitation to contort the meaning of an IRP acknowledgment to suit STOP B2H's misguided interpretation of EFSC's rules.

D. B2H and Carbon Reduction Goals

The Company believes that the B2H project is foundational to a clean energy future for Idaho Power and the Western grid. Increased transmission connectivity is widely viewed as a critical component to meeting future carbon reduction goals.[55] In addition to Idaho Power's own clean energy goals, the Company understands that the new Presidential Administration intends to focus on clean energy—including prioritizing necessary transmission infrastructure.[56] Idaho Power is pursuing various options to move toward a clean energy future, but without transmission other clean energy options cannot be fully leveraged.

STOP B2H believes that B2H should not be referred to as a carbon-free supply-side resource because the line will enable market purchases of energy that are not necessarily carbon free, especially in the near term.[57] The Company cannot limit energy transmitted across the line to renewable energy only, but in order to transition to a clean energy future, robust transmission must be available in order to access renewable resources in different geographic areas. The Company would like to encourage STOP B2H—and all stakeholders—to view B2H as a long-term resource, keeping in mind the current direction of the industry. As Renewable Northwest states, "additional transmission builds can 'provid[e] Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric

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[54] Order No. 18-176 at 1, 9.
[55] *See, e.g.,* National Renewable Energy Laboratory, Renewable Electricity Futures Study at 25 (2012) (https://www.nrel.gov/docs/fy13osti/52409-ES.pdf).
[56] Executive Order No. 14008, 86 FR 7619 (Jan. 27, 2021).
[57] STOP B2H's Final Comments at 32-33.

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market.'"[58] Indeed, Renewable Northwest recognizes that clean energy resources have "the ability to provide capacity (or reduce or manage demand) without creating the costs and risks associated with stranded assets, especially given the possibility of a future policy scenario where most or all of the region's supply must be generated using clean, non-emitting resources and the policy direction of EO 20-04."[59]

The Company's vision of the Pacific Northwest's future energy supplies is similar to that of Renewable Northwest. Clean energy will take the place of fossil fuels, and transmission will be key to moving that carbon-free energy to load. In this way, available energy resources will decarbonize, as will the energy transmitted via B2H. In sum, B2H is not only a least-cost, least-risk resource today, but will also continue to enable the transition to a clean energy future.

E. Mid-C Market and Market Purchase Opportunities in the Pacific Northwest

STOP B2H broadly objects to the Company's reliance on western markets in evaluating the potential supply-side benefits of B2H.[60]

First, STOP B2H does not agree with the Company's analysis of the flexibility, liquidity, reliability, and low cost of market purchases at the Mid-Columbia ("Mid-C") trading hub.[61] As Idaho Power explained in its *Second Amended 2019 IRP*, Appendix D, the Mid-C hub is very liquid.[62] In 2018, on a day-ahead basis, daily average trading volume during heavy-load hours in June and July ranged from nearly 10,000 MWh to over 29,000 MWh. Despite these facts, STOP B2H claims that regional resource adequacy concerns, identified by the Northwest Power Conservation Council's ("NWPCC") Pacific Northwest Power Supply Assessment for

[58] Renewable Northwest's Final Comments at 2 (quoting Idaho Power's initial 2019 IRP) (Jan. 8, 2021).
[59] Renewable Northwest's Final Comments at 4 (emphasis added).
[60] STOP B2H's Final Comments at 30-33.
[61] STOP B2H's Final Comments at 5, 30.
[62] Second Amended 2019 IRP, Appendix D at 8.

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2024, and the prices established for the forthcoming Jackpot Solar generating facility, indicate that the Mid-C is an unreliable source of long-term market purchases.[63] Idaho Power disagrees.

With respect to the reference to NWPCC's Assessment, Idaho Power is a stakeholder in NWPCC processes and studies, which provide the region with useful information to assist in planning decisions. Typically, Idaho Power would have included an analysis of this report in Appendix D; however, this Assessment had not yet been released when the Company developed Appendix D in this case. As a result, the Company will briefly summarize its understanding of the implications of the NWPCC Assessment here.

By way of background, the focus of the NWPCC Assessment is on electric utilities in the Northwest United States and their resources.[64] The study makes only limited allowances for the transmission connectivity of the region and independent power producers within the region. More critically for Idaho Power, the NWPCC Assessment continues to show that the primary issues faced by the Northwest, on average, are in the winter months. Figure 1, below, shows that the severity of loss of load expectation ("LOLE") in July and August are dwarfed by events in the winter months. The Northwest's primary issue remains in the winter—not during Idaho Power's peak summer season in late June and early July.

[63] STOP B2H's Final Comments at 30.
[64] NWPCC, Pacific Northwest Power Supply Adequacy Assessment for 2024 at 24 (Oct. 31, 2019) https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf.

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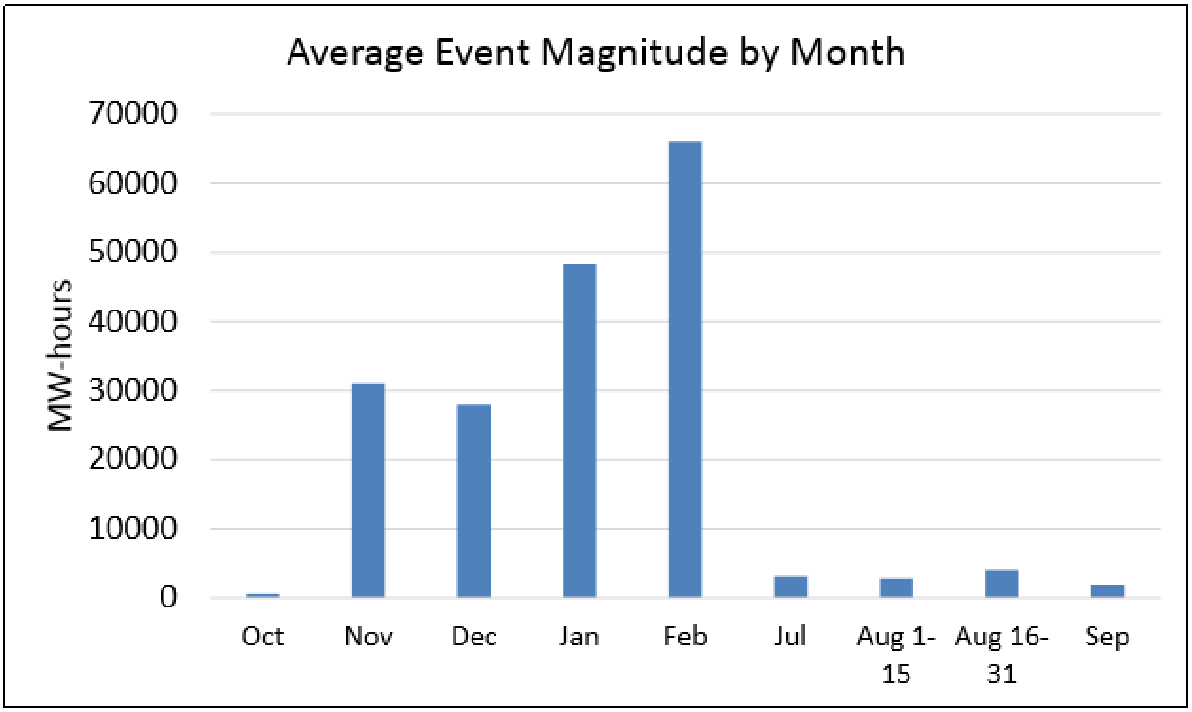
Figure 1: NWPCC Assessment of Average LOLE Magnitude[65]



Looking forward strategically, the Northwest region is on a clean-energy trajectory and the Company expects the region will address the winter LOLE risk with renewable energy, such as optimally located renewables, optimized hydro, and storage solutions. These new resources will address regional winter LOLE risk and eliminate the (already much less severe) summer LOLE risk. In fact, solar-plus-storage and solar-plus-wind are even more effective at addressing summer peak than they are at addressing winter peak. In the summer, once the solar ramps down, there are only a few hours remaining until the late evening hours. Storage can come in the form of short-duration batteries (which utilities such as Idaho Power can combine with solar projects) or hydro generation (which has great amounts of capacity but limited energy). B2H fits very well within these opportunities by enabling access via transmission to these supporting resources.

[65] NWPCC, Pacific Northwest Power Supply Adequacy Assessment for 2024 at 15.

Winter LOLE risk is more challenging due to the dual morning and evening peaks before and after sun-down. Critically, this is the period during which transmission such as B2H is likely to play an even larger role by connecting remote renewable resources to load centers. While STOP B2H interprets the NWPCC Assessment as suggesting a lack of adequate market capacity, Idaho Power understands the report as reinforcing the need to improve access to power when and where there is heightened demand.

Next, with respect to Jackpot Solar, STOP B2H claims that this resource was identified as a more cost-effective resource than Mid-C. Idaho Power understands STOP B2H as claiming that, by extension, market purchases are over-priced.[66] Idaho Power agrees the Jackpot Solar resource is very cost-effective, which is why the Company executed a Power Purchase Agreement ("PPA") to purchase the project's output. But the Company 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. Mid-C is, in point of fact, a market like any other, 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, for example. Rather, B2H provides a different value to the Company's customers in the form of a firm, and diverse, resource—for instance, by providing access to power in those hours after the sun goes down.

Finally, STOP B2H claims that the Company included 1,800 MW of "phantom coal generation" selling into the Mid-C hub by including Boardman and Centralia throughout the 20-year planning period.[67] This claim is false. The data request referenced by STOP B2H asked for resources and resource retirements selected by AURORA. Retirement dates for

[66] STOP B2H's Final Comments at 5
[67] STOP B2H's Final Comments at 33.

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the three plants mentioned were not selected by AURORA. These retirements were modeled as follows:

(1) Centralia 1 – December 2020
(2) Boardman – End of Year 2020
(3) Centralia 2 – December 2025

Notably, the Transalta natural gas units were retired December 2013 in the AURORA resource table; therefore, they were not included in the analysis as STOP B2H claims. STOP B2H also claims that the Company "zero[ed] out BPA's existing wheeling charges assessed to Idaho imports from the PNW, by incorporating a phantom asset swap with BPA into the B2H cases."[68] Not only does STOP B2H provide no basis for its claim, the assertion is simply not true. The Company modeled BPA's wheeling rate on the B2H segment in the AURORA model.[69]

F. B2H and Transmission Path Constraints

STOP B2H objects to the Company's analysis of the path between the Northwest and Idaho, and Idaho Power's treatment of the capacity across that path.[70] Specifically, STOP B2H claims that the Company's capacity constraints are manufactured, stating that the Company's actual transmission flows often exceed the existing transmission path's West-to-East commercial rating.[71] Here, STOP B2H fails to understand how transmission capacity is contracted for in the West, and the difference between a transmission line's commercial transmission capacity and actual power flows. Contractual capacity defines the amount of firm capacity that can be reserved on a transmission line, while actual power flows are just that—the amount of power that actually flows on the path.

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[68] STOP B2H's Final Comments at 33.
[69] Idaho Power reviewed its transmission assumptions in the IRP review process, and documented updates in Table 5.1 of the IRP Review Report. Areas of the table without information reflect no update was necessary. Wheeling charges with respect to B2H were modeled at $2.83/MWh. Second Amended 2019 IRP, Attach. 3, 2019 IRP Review Report at 58.
[70] STOP B2H's Final Comments at 6.
[71] STOP B2H's Final Comments at 6.

The typical commercial path rating between the Northwest and Idaho (Path 14) in the summer months is 1,200 MW. This means that the transmission provider cannot grant firm transmission requests over and above 1,200 MW. It is true that, over the past few years, the Company has seen actual flows exceeding this amount, and at times flow has exceeded 1,200 MW by hundreds of megawatts. This flow over 1,200 MW is called "adverse unscheduled flow," which can be caused by several events, but is typically associated with commercial schedules elsewhere experiencing opposing conditions—*i.e.*, the path is scheduled but the power is not flowing. Controlling real power flow on a single path within an interconnected power system is challenging and requires significant coordination between utility real-time operations centers and the reliability coordinator. To be clear, the fact that actual power flows exceed a commercial path rating does not mean that capacity constraints do not exist. STOP B2H's argument (perhaps understandably) confuses the discrete physical and contractual approaches to transmission planning and operation in the West.

With respect to the specific issue STOP B2H identifies, B2H will add 1,050 MW of West-to-East capability to Path 14 and will provide significant operational flexibility to Idaho Power.[72] Adverse loop flow (such as the type that can lead to flows well in excess of path ratings) is becoming a significant operational issue and solving this problem by increasing the path rating is an ancillary benefit of B2H that the Company has not quantified in this IRP analysis.

Next, STOP B2H asserts that "there has not been a date that we could find, where [Idaho Power] could not purchase the power it wanted from the Mid-C."[73] First, it is not clear on what evidentiary basis STOP B2H rests its assertion. To verify STOP B2H's claim, one would need to conduct a detailed examination of real-time grid operations to determine what

[72] Second Amended 2019 IRP, Appendix D at 15.
[73] STOP B2H's Final Comments at 6.

power is procured from where at any given point to meet changing load. STOP B2H provided no evidence of such examination. That said, Idaho Power can certainly attest that the grid experiences significant stress and, in almost all cases, transmission capacity—not generation—is the constraint. The Summer 2020 California rolling outages are prime examples of this transmission constraint. On August 18, 2020, resources were available at the Mid-C market hub; however, deliverability constraints (transmission) limited that market's ability to provide support to the desert Southwest. This was indicated by the major price spread that occurred on August 18, 2020, with the Mid-C price getting to about $200 per MWh, whereas the Palo Verde market hub (desert Southwest) price exceeded $1,500 per MWh. Second, Idaho Power would note that STOP B2H's statement concerning the apparent adequacy of the Mid-C market and Idaho Power's ability to readily rely on such market purchases appears to be in tension with STOP B2H's earlier questioning of the liquidity of the Mid-C market hub.

STOP B2H raises concerns with Idaho Power's calculation and use of Transmission Reliability Margin ("TRM") and Capacity Benefit Margin ("CBM"). In the mid-1990s, FERC issued a series of orders that required transmission providers to calculate and post for sale their Available Transfer Capacity ("ATC"). As part of that calculation, FERC determined that it was important for the reliability of the system for utilities to create two margins that are deducted from ATC: TRM and CBM. Over the past several decades, FERC and the North American Electric Reliability Corporation ("NERC") issued orders and promulgated rules that require specific calculations of TRM and CBM as inputs to the ATC methodology, the results of which are now contained in Idaho Power's FERC-approved OATT. Regardless of STOP B2H's concerns, Idaho Power follows and must continue to follow FERC-approved rules related to calculation and applicability of TRM and CBM, which requires withholding TRM and CBM amounts from its ATC.

STOP B2H further suggests that Idaho Power inappropriately holds back transmission capacity in the form of TRM.[74] As an initial matter, the Company has already addressed these concerns in prior comments.[75] As stated above, Idaho Power is required by FERC to calculate a certain amount of TRM for transmission paths on its system and withhold that amount from its ATC. And to reiterate, TRM allows the Company to maintain adequate transmission capacity to account for unscheduled flow, such as the adverse unscheduled flow mentioned above. As described in its OATT, Idaho Power makes this capacity available for non-firm usage and, when flows reach unmanageable levels, it is curtailed.

Next, STOP B2H claims that Idaho Power should eliminate "some or all" of the 330 MW of CBM by adding new resources within the Company's Balancing Authority Area ("BAA").[76] This argument echoes STOP B2H's prior comments, which argued that CBM can and should be used as a resource to offset the need for B2H.[77] In Idaho Power's prior Reply Comments, the Company provided a detailed discussion of the scope and purpose of CBM, explaining that CBM is capacity set aside for system emergencies, but is nonetheless already included in the Company's IRP as part of the Company's Planning Margin.[78] Nonetheless, STOP B2H now states that "Idaho Power misrepresented STOP [B2H]'s comments and invented a new undefined term 'emergency transmission' to belittle STOP [B2H]'s suggestion."[79]

To be clear, Idaho Power did not belittle STOP B2H's suggestion by describing CBM colloquially as "emergency transmission." Rather, the Company explained the function of

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[74] STOP B2H's Final Comments at 6.
[75] Idaho Power's Reply Comments at 11-12.
[76] STOP B2H's Final Comments at 34.
[77] STOP B2H's Amended and Revised Opening Comments at 19 (April 7, 2020).
[78] Idaho Power's Reply Comments at 11.
[79] STOP B2H's Final Comments at 34.

CBM in an accessible manner. In contrast, the actual definition of CBM out of the NERC glossary is as follows:

> The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.[80]

In summary, CBM is, by definition, a transmission margin that is set aside for times of emergency generation deficiencies and removal of the CBM from a transmission provider's ATC is mandated by FERC.

With respect to STOP B2H's claim that adding new resources within Idaho Power's BAA would eliminate the need for a CBM "at no incremental cost," this assumption is incorrect.[81] Whether it is more affordable to add one type of resource (such as B2H) over another (such as new generation within Idaho Power's BAA) is precisely the question that the IRP process is designed to answer. As the Company's portfolio analysis demonstrates, the cost of necessary resources in the absence of B2H would be far greater than the cost of building B2H.

Similarly, if Idaho Power were to replace the emergency reserve provided by CBM with another on-system resource, then the Company would be in precisely the same position for resource planning purposes—in need of generation to meet that same 330 MW—because emergency support not provided by CBM would need to be provided by something else. Thus, reducing or eliminating CBM simply moves the need for capacity from one bucket (serving

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[80] NERC Glossary of Terms, available at: https://www.nerc.com/files/glossary_of_terms.pdf.
[81] STOP B2H's Final Comments at 34.

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load) to another bucket (planning margin), while having zero impact on the Company's overall system need.

Finally, STOP B2H states that the Company has been selling 200 MW of the CBM to BPA on a conditional firm basis since 2016.[82] STOP B2H goes on to imply that such a conditional firm sale violates the Company's OATT, and that STOP B2H intends to pursue the issue through FERC's Enforcement Division.[83]

Section 15.4 of Idaho Power's OATT requires Idaho Power to offer conditional firm transmission service to its transmission customers when insufficient capacity exists on its system to grant the customer's full transmission service request. Idaho Power and BPA entered into these conditional firm service agreements and filed them with FERC in 2016.[84]

STOP B2H appears to be confusing *conditional firm* service, which is subject to significant curtailment limitations, with *firm* service, which must be available in all but emergency conditions. Because CBM is designed to serve as emergency support, the Company appropriately allows efficient use of this reserve when not needed for emergency purposes, as required by FERC orders.

IV. PORTFOLIO DESIGN AND ANALYSIS

In its comments, Staff raises a number of concerns regarding the Company's portfolio construction and risk analysis process, and requests additional clarification in the Company's Final Comments. Staff also provides additional recommendations to enhance the 2021 IRP.[85] STOP B2H notes perceived deficiencies in the Company's stochastic risk analysis.[86] Parties'

[82] STOP B2H's Final Comments at 34.
[83] STOP B2H's Final Comments at 34.
[84] Idaho Power's agreements with BPA can be found in Idaho Power's FERC-approved OATT as Service Agreement Numbers 324 and 342.
[85] Staff's Final Comments at 22-31
[86] STOP B2H's Final Comments at 24-25.

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comments on the various portfolio development and analysis components are addressed in turn.

A. The Company Commits to Improving Portfolio Naming Conventions.

Staff strongly critiques the Company's naming conventions used in the portfolio construction process, describing the nomenclature as "confusing."[87] Upon review, Idaho Power recognizes that both the portfolio and table naming conventions in this *Second Amended 2019 IRP* can be confusing. The Company commits to developing clearer explanations and nomenclature in the future.

As parties have noted, the *Second Amended 2019 IRP* is the result of a highly intensive review of Idaho Power's entire planning process and methodology, meaning that the Company was heavily immersed in the details of the review process and subsequent analysis over a compressed time period. In the interests of ensuring both transparency and accuracy, the Company placed a greater emphasis on documenting each and every step of review and analysis, and—in the process—overlooked the importance of easily understood naming conventions. With the benefit of time and other parties' comments, the Company has identified improvements that will be made to naming conventions and descriptions in future IRP cycles.

Moving forward, the Company will make a concerted effort to better communicate and present analysis in the 2021 IRP, including through naming conventions, with full recognition that high-quality communication is the key that unlocks the complex and technical IRP process.

B. Risk Analysis

1. Idaho Power Agrees to Incorporate Qualitative Risk Measures in the 2021 IRP.

Staff's Final Comments note that the Company did conduct a qualitative evaluation of

[87] Staff's Final Comments at 22.

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risk, but would have expected qualitative measures to be applied across all portfolios to yield portfolio-specific results.[88] Staff recommends that the Company report qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward.[89]

As Staff correctly noted, in Chapter 9 of the *Second Amended 2019 IRP*,[90] the Company identifies and discusses major qualitative risks as part of the portfolio analysis process, but the Company agrees with Staff that a comparison of these qualitative risks across portfolios would have been beneficial. Idaho Power commits to reporting qualitative benefits and risks by portfolio in the 2021 IRP.

2. <u>Idaho Power Appropriately Conducted Stochastic Risk Analysis.</u>

In its final comments, STOP B2H reiterates its claim that Idaho Power failed to consider carbon risk in the stochastic analysis.[91] STOP B2H further claims that, in this *Second Amended 2019 IRP*, Idaho Power structured the stochastic analysis to bias the analysis against all portfolios that were optimized under a high carbon cost future.[92]

Contrary to STOP B2H's claims, Idaho Power looked extensively at carbon price futures throughout the portfolio development process. STOP B2H suggests that Idaho Power should have used stochastic risk analysis to evaluate carbon prices. Idaho Power disagrees. The intent of stochastic analysis is to examine the risk associated with unpredictable or uncertain variables, such as weather or water levels. In contrast, there are many real examples of carbon prices curves from proposed or implemented policies. Idaho Power believes that little would be gained from stochastic analysis of carbon pricing while, in contrast, much can be learned from evaluating resource portfolios at various carbon price curves, as the Company has done.

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[88] Staff's Final Comments at 25.
[89] Staff's Final Comments at 26.
[90] Second Amended 2019 IRP at 124-126.
[91] STOP B2H's Final Comments at 24.
[92] STOP B2H's Final Comments at 25.

To that end, Idaho Power's Long-Term Capacity Expansion ("LTCE") modeling was performed under three natural gas price forecasts and four carbon price forecasts[93] to develop optimized resource portfolios for a range of possible future conditions. Various carbon price futures were further analyzed on select portfolios during the manual portfolio development process. In fact, two of the three portfolio groupings selected for manual optimization were developed under a high-carbon price scenario,[94] precisely to account for a range of possible policy futures. As such, the Company adequately evaluated carbon cost risk. Please see Chapter 9 of the *Second Amended 2019 IRP* for the full discussion of carbon pricing in the portfolio development process and stochastic risk analysis.

C. Idaho Power's 2021 IRP Modeling Will Be Able to Optimize Portfolios for the Company's System.

In its final comments, Staff reiterates the need to ensure that resource selections are optimized for Idaho Power in particular and recommends the Company devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop.[95] The Company agrees with Staff that the 2021 IRP should optimize resource buildouts within Idaho Power's system. The Company, however, wishes to note the importance of a model's ability to concurrently optimize resources for both Idaho Power's system and the broader Western Electricity Coordinating Council ("WECC") to produce market prices and operating conditions that are representative of specific modeled scenarios. This is an important distinction, as resources selected for the WECC influence each portfolio's NPV for Idaho Power's system. The rationale for, and benefits of, including the broader WECC are described below. To conduct the 2021 IRP, Idaho Power will use the latest version of AURORA, which can achieve

[93] Second Amended 2019 IRP at 106.
[94] *See* Second Amended 2019 IRP, Table 8.5 at 110.
[95] Staff's Final Comments at 26.

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simultaneous optimization of Idaho Power's system and the WECC. The Company will discuss these updates to AURORA at upcoming meetings of the 2021 IRP Advisory Council.

D. Idaho Power Will Expand the Modeling Scenarios in the 2021 IRP.

Staff notes that, in the Company's *Second Amended 2019 IRP*, the Company included a more diverse set of scenarios for consideration in developing and analyzing portfolios. However, upon review of the data, Staff calculates the correlation of portfolio NPV among the scenarios and concludes that, due to the high correlation between the gas scenarios, the differences in portfolios were largely driven by the carbon cost component. Staff does not object to this approach but recommends that more scenarios be used in the future to more thoroughly evaluate risk. Ultimately, Staff recommends the Company implement a more robust measure of cost risk for evaluating portfolios in the 2021 IRP.[96]

Idaho Power appreciates Staff's analysis and recommendations. For the 2021 IRP, the Company plans to adopt Staff's recommendation and will supplement its risk evaluation methods. For instance, the Company will plan to conduct more portfolio sensitivity analyses, which will allow Idaho Power to assess risks and scenarios that vary from those used to create the initial portfolios.

E. Idaho Power Manually Adjusted Portfolios to Optimize the Resources for Idaho Power's System.

Staff has asked the Company to clarify the manual portfolio adjustments, and specifically how the Company applied the guiding principles used in the manual optimization process.[97]

To review, the LTCE model in AURORA selects the most cost-effective resources to meet growing demand and system needs for the entire WECC region. This modeling was

[96] Staff's Final Comments at 26-29.
[97] Staff's Final Comments at 29. Idaho Power system resource selections for Tables 9.5 and 9.6 in the main IRP Report are presented in Technical Appendix C, pages 58-69.

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designed to produce 24 portfolios under varying carbon cost and natural gas forecasts, and with and without the B2H transmission line.[98] Each run resulted in a different resource selection for Idaho Power's system *and* a resource selection for the rest of the WECC region (as part of optimizing for WECC as a whole). That is, each run identified resources needed to cost-effectively serve the entire WECC and identified a resource portfolio for Idaho Power as a subset of the WECC. Thus, while the resource additions and retirements developed by AURORA in Portfolios 1-24 represent Idaho Power's system, the resource selections and timing were nevertheless optimized for the entire WECC. The selection of resources and timing of the buildouts for Portfolios 1-24 are shown on pages 47-57 of Technical Appendix C.

It is important for AURORA to account for all WECC-wide resources because the cost to serve Idaho Power's system depends on the resources selected for the WECC, including the resources selected within Idaho Power's system. This dependency occurs because different WECC-wide resources impact market prices, which are calculated within the AURORA model. Thus, different WECC resource selections outside of Idaho Power's system result in variations to the NPV of Idaho Power's portfolio.

Notably, Idaho Power's average demand is approximately 2 percent of the WECC's overall average demand.[99] By optimizing for the WECC as a whole, the resource additions and retirements under these runs may not reflect the lowest cost for Idaho Power's system. To correct for these non-optimal portfolio costs caused by the AURORA LTCE designing for the WECC as a whole, rather than Idaho Power's system individually, Idaho Power performed a series of manual adjustments to identify the least-cost, least-risk portfolio based on Idaho

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[98] Second Amended 2019 IRP at 107.

[99] While there are some exceptions, optimized portfolios tend to add resources as they are needed and generally only in the required quantities because overbuilding the system with additional resources often results in higher portfolio costs.

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Power's system needs. Fortunately, the limitations in AURORA appear to have since been resolved by Energy Exemplar, the model's developer.

To begin the manual optimization process, Idaho Power grouped the WECC-optimized portfolios with similar resource buildouts and timing, both for B2H and non-B2H portfolios:

Table 1: WECC-Optimized Portfolios Selected for Manual Adjustments[100]

Category	B2H Portfolios	Non-B2H Portfolios
Planning Gas, Planning Carbon (PGPC)	P(13), P(14)	P(1), P(2)
Planning Gas, High Carbon (PGHC)	P(15), P(16)	P(3), P(4)
High Gas, High Carbon (HGHC)	P(23), P(24)	P(11), P(12)

As an example, the table below shows the four WECC optimized portfolios that were grouped to inform the PGPC manually optimized scenarios. The resource types and quantity are very similar between the portfolios.

[100] Second Amended 2019 IRP, Table 8.5 at 110.

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Table 2: WECC-Optimized Portfolios grouped to inform PGPC Manually Optimized Scenarios

	Non-B2H		B2H	
Portfolio	Portfolio 1	Portfolio 2	Portfolio 13	Portfolio 14
Thermal	933	933	711	600
Wind	0	0	0	0
Solar	320	320	200	320
Battery	90	80	50	80
Demand Response	50	50	45	45
Transmission (B2H)	n/a	n/a	500	500
Coal Exits	-1,026	-1,026	-1,026	-1,026

The three distinct portfolio groupings—or categories—reflect a wide range of natural gas and carbon price futures and B2H and non-B2H alternatives, allowing Idaho Power the opportunity to evaluate a variety of portfolios for manual optimization, rather than a narrower selection of portfolios that looked somewhat similar in terms of resource selection and timing—a critique of Idaho Power's manual adjustment process in the past.[101] This selection of a broader range of portfolios for manual optimization allowed the Company to determine if further cost reductions were possible for Idaho Power's specific system needs.

The Company's manual adjustment process focused on identifying optimal exit scenarios for the Company's Jim Bridger coal units. The first three scenarios evaluated three different sets of Jim Bridger exit dates to apply to the new portfolio groupings (Non-B2H and B2H for Planning Gas-Planning Carbon ("PCPG"), Planning Gas-High Carbon ("PGHC"), and High Gas-High Carbon ("HGHC")). The guiding principles for adjusting portfolios based on these scenarios appear on page 115 of the *Second Amended 2019 IRP*, also set forth below:

[101] Second Amended 2019 IRP at 109-110.

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- Applying the same modeling constraints used within the AURORA model during the WECC optimization (e.g., Bridger unit exits could not be earlier than the dates identified in Scenario 1);
- Utilizing the same resource types and approximate resource allocations identified in the WECC-optimized LTCE portfolios;
- Resources were deferred and reduced where possible while maintaining a planning margin of 15 percent; and
- No carbon emitting resources were added to the HGHC portfolios.

The following table and highlighted cells show how resources were adjusted in manual optimization (Portfolios PGPC(1) and PGPC B2H (1)) compared to the WECC-optimized portfolios included in the PGPC grouping (Portfolios 1, 2, 13, and 14). For instance, in PGPC B2H (1), below, additional solar—especially when paired with battery storage—allows the Company to significantly reduce selection of thermal resources, reducing overall costs.

Table 3: Resource Adjustments Between WECC-Optimized and Manually Optimized Portfolios Under PGPC Scenario 1

	Non-B2H			B2H		
Portfolio	Portfolio 1	Portfolio 2	PGPC (1)	Portfolio 13	Portfolio 14	PGPC B2H (1)
Thermal	933	933	933	711	600	411
Wind	0	0	0	0	0	0
Solar	320	320	320	200	320	400
Battery	90	80	80	50	80	80
Demand Response	50	50	50	45	45	45
Transmission (B2H)	n/a	n/a	n/a	500	500	500
Coal Exits	-1,026	-1,026	-1,026	-1,026	-1,026	-1,026

Other examples of adjustments (upward or downward) in the quantity of resources can be found by comparing the WECC-optimized portfolios (p. 46-57) to the manually optimized portfolios (p. 58-69) in Technical Appendix C. The adjustments identified in the table above were ultimately reflected in the manually optimized portfolios, reducing the cost for Idaho Power's system. This process was utilized to manually adjust the PGPC, PGHC, and HGHC portfolios for three Jim Bridger exit scenarios, yielding 18 new portfolios (three scenarios applied to three different carbon/gas futures, both with and without B2H).

Once Idaho Power used manual optimization to identify the optimal (that is, least-cost) exit scenario for Jim Bridger units, the Company performed a fourth manual adjustment in an attempt to further refine the results of the first three scenarios, creating 8 additional portfolios (portfolios developed under this fourth scenario exercise are denoted as "(4)" under each carbon/gas planning future with and without B2H). In addition to the guiding principles applied in the first three scenarios, the guiding principles on page 116 of the *Second Amended 2019 IRP*, set forth below, provided the sideboards for portfolio adjustments in scenario four:

- Large-scale combined cycle combustion turbine ("CCCT") units can, in some cases, be replaced with more scalable reciprocating gas engines, allowing a phased approach to adding flexible resources that reduces costs.
- Demand response can be accelerated and/or expanded to defer some types of resources.
- Depending on the portfolio builds, accelerating solar and battery resources and alternating with flexible resources can result in portfolio savings.
- Solar-plus-battery resources are often selected before solar-only resources because they allow a higher contribution to peak.

The table below shows how the Company adjusted Non-B2H and B2H portfolios PGPC(1) under the guiding principles described above. For instance, manual adjustments created Non-B2H PGPC (4) by adding one 300 MW CCCT in 2035 and additional reciprocating engines, as opposed to the two 300 MW CCCTs selected for Non-B2H

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PGPC (1) in years 2029 and 2031. Testing the cost-effective adoption of flexible resources at different sizes—smaller reciprocating engines versus one large CCCT—was an attempt to decrease portfolio cost while accelerating solar and battery resources and reducing reliance on thermal resources.

Table 4: Resource Adjustments Between Manually Optimized PGPC Scenario 1 and Scenario 4

	Non-B2H		**B2H**	
Portfolio	PGPC(1)	PGPC (4)	PGPC B2H (1)	PGPC B2H (4)
Thermal	933	911	411	389
Wind	0	0	0	0
Solar	320	360	400	440
Battery	80	80	80	80
Demand Response	50	50	45	45
Transmission (B2H)	n/a	n/a	500	500
Coal Exits	-1,026	-1,026	-1,026	-1,026

However, while the objective of the fourth scenario was to determine if an even lower-cost resource portfolio could be developed by testing the introduction and removal of certain technologies, the Company found that this fourth scenario exercise did not produce a lower-cost portfolio compared to the prior three manually adjusted scenarios.

The Company believes that the process and examples in this section provide the necessary insight into the systematic process the Company followed when making the manual adjustments to the portfolios. In total, the manual adjustment process yielded 24 additional portfolios that were further evaluated in the AURORA model to determine their NPV, the results of which were shown in Tables 9.5 and 9.6 of the *Second Amended 2019 IRP*.[102]

[102] Second Amended 2019 IRP at 117-118.

F. Table 9.6 Provides the Relevant Basis for Identifying the Preferred Portfolio.

Staff was unclear what the data in Tables 9.5 and 9.6 in the *Second Amended 2019 IRP* represent and requests clarification from Idaho Power.[103] Idaho Power apologizes for the confusion and recognizes that the descriptions do not offer full clarity. In short, and as explained in more detail below, the two tables present the NPV of the different manually adjusted portfolios, but each table offers a different point of comparison.

Specifically, Table 9.5 shows how each Idaho Power resource portfolio performs under the four different planning futures, as influenced by the broader WECC-wide resources that were identified during the LTCE model runs. As explained above, different non-Idaho Power, WECC-wide resources impact market prices, which are calculated within the AURORA model. Thus, different WECC resource selections outside of Idaho Power's system result in variations to the NPV of each Idaho Power portfolio. Thus, to determine the NPV for each of Idaho Power's resource portfolios, the Company ran each manually adjusted portfolio through a cost model. This cost model evaluated the costs of the Company's portfolio under a particular planning future, and also accounted for the influence of the non-Idaho Power, WECC-wide resources on Idaho Power's portfolio costs.

Note, Idaho Power's manual adjustment process did not modify the non-Idaho Power WECC resources identified by AURORA in the LTCE resource modeling process. As a result, the non-Idaho Power resources used for each cost run were the same non-Idaho Power resources identified by the LTCE portfolio development process for that scenario. For instance, in the highlighted cell below, the HGHC(1) portfolio, examined in a PCPG future, evaluated the costs of Idaho Power's resource portfolio, as influenced by the non-Idaho Power

[103] Staff's Final Comments at 29.

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resources identified by AURORA in planning for a HGHC future. That is, the non-Idaho Power resources match the portfolio—not the future carbon and natural gas cost scenario.

Table 5: Table 9.5 in *Second Amended 2019 IRP* manually built portfolios, NPV years 2019–2038 ($ x 1,000)

NPV ($ x 1000)		Planning Gas—Planning Carbon	High Gas—Planning Carbon	Planning Gas—High Carbon	High Gas—High Carbon
PGPC (1)	Cost run of Idaho Power HGHC(1) resources, influenced by the full WECC (including non-Idaho Power resources), all of which were identified under high gas, high carbon case, no B2H	$6,279,509	$7,426,379	$8,233,137	$9,440,332
PGPC (2)		$6,273,071	$7,246,081	$8,490,274	$9,625,390
PGPC (3)		$6,284,277	$7,277,944	$8,431,678	$9,560,285
PGPC (4)		$6,279,772	$7,259,024	$8,558,682	$9,716,348
PGHC (1)		$6,390,311	$7,319,067	$8,032,346	$9,067,148
PGHC (2)		$6,442,048	$7,144,213	$8,264,118	$9,181,798
PGHC (3)		$6,453,111	$7,181,508	$8,242,129	$9,151,410
PGHC (4)		$6,294,814	$7,359,094	$8,091,963	$9,277,557
HGHC (1)		$7,469,519	$7,934,725	$8,635,143	$9,153,185
HGHC (2)		$6,987,986	$7,521,331	$8,665,974	$9,374,281
HGHC (3)		$7,043,235	$7,575,393	$8,654,276	$9,326,503
HGHC (4)		$6,855,447	$7,783,286	$8,595,740	$9,639,967
PGPC B2H (1)		$6,239,229	$7,436,314	$8,389,315	$9,634,337
PGPC B2H (2)		$6,267,445	$7,285,695	$8,662,735	$9,863,352
PGPC B2H (3)		$6,267,257	$7,327,131	$8,650,207	$9,858,607
PGPC B2H (4)		$6,247,768	$7,457,533	$8,453,137	$9,705,863
PGHC B2H (1)		$6,342,373	$7,377,938	$8,113,174	$9,290,421
PGHC B2H (2)		$6,326,907	$7,223,445	$8,356,141	$9,518,984
PGHC B2H (3)		$6,325,327	$7,260,956	$8,336,880	$9,508,616
PGHC B2H (4)		$6,231,882	$7,378,575	$8,244,490	$9,576,761
HGHC B2H (1)		$6,627,133	$7,560,819	$8,321,638	$9,377,658
HGHC B2H (2)		$6,551,203	$7,370,092	$8,519,476	$9,591,880
HGHC B2H (3)		$6,549,962	$7,402,601	$8,507,236	$9,581,960
HGHC B2H (4)		$6,505,943	$7,500,370	$8,259,364	$9,394,863

In examining the results of this cost modeling, the Company noted that very similar Idaho Power resource portfolios occasionally yielded cost differences under the same planning future. Thus, it appeared that the non-Idaho Power resources—rather than the cost of the Company's resource portfolios themselves—impacted the relative portfolio costs. As a result, Table 9.5 is of limited utility in understanding how the cost of Idaho Power's different resource portfolios compare in a given planning future because the costs reflect, in part, differences in the broader WECC rather than the direct comparison of resources selected in each of the portfolios of Idaho Power's resources. This finding led the Company to develop Table 9.6, to control for the impacts of the non-Idaho Power resources in the broader WECC.

Table 9.6 shows how each of Idaho Power's resource portfolios performs under the four different planning futures but allows for comparisons across the portfolios by holding the non-Idaho Power resources within the WECC constant *across* portfolios and *within* different futures. That is, when examining how each Idaho Power resource portfolio performed in a particular natural gas and carbon cost future, with and without B2H, the Company used the non-Idaho Power resources that were identified by AURORA in the LTCE runs *for the future being examined*. This approach allowed Idaho Power to understand how the Company's resource portfolios would be impacted by the development of non-Idaho Power buildouts, where those buildouts aligned with the planning future under consideration. To perform this analysis, the Company used the non-Idaho Power, broader WECC resources developed by AURORA in the initial LTCE runs that corresponded to each of the eight futures being examined (four combinations of planning/high gas and planning/high carbon, each analyzed with and without B2H). This use of consistent non-Idaho Power buildouts from the broader WECC to analyze the impacts on Idaho Power's manually adjusted portfolios is depicted in the chart below, with each block of color using a single non-Idaho Power resource buildout in the cost run.

Table 6: Table 9.6 in *Second Amended 2019 IRP* manually built portfolios, NPV years 2019–2038 ($ x 1,000)

NPV ($ x 1000)	Planning Gas—Planning Carbon	High Gas—Planning Carbon	Planning Gas—High Carbon	High Gas—High Carbon
Portfolio PGPC (1)	$6,279,509	$7,411,931	$8,114,621	$9,345,007
Portfolio PGPC (2)	$6,273,071	$7,236,437	$8,331,134	$9,504,866
Portfolio PGPC (3)	$6,284,277	$7,269,646	$8,292,583	$9,443,642
Portfolio PGPC (4)	$6,279,772	$7,238,655	$8,378,158	$9,552,907
Portfolio PGHC (1)	$6,400,413	$7,334,372	$8,032,346	$9,083,275
Portfolio PGHC (2)	$6,451,515	$7,164,818	$8,264,118	$9,205,845
Portfolio PGHC (3)	$6,462,698	$7,201,220	$8,242,129	$9,176,938
Portfolio PGHC (4)	$6,310,357	$7,363,283	$8,091,963	$9,237,188
Portfolio HGHC (1)	$7,465,092	$7,907,690	$8,603,701	$9,153,185
Portfolio HGHC (2)	$7,000,131	$7,508,566	$8,642,228	$9,374,281
Portfolio HGHC (3)	$7,052,572	$7,564,816	$8,632,474	$9,326,503
Portfolio HGHC (4)	$6,918,876	$7,819,991	$8,652,244	$9,639,967
Portfolio PGPC B2H (1)	$6,239,229	$7,392,339	$8,091,379	$9,349,587
Portfolio PGPC B2H (2)	$6,267,445	$7,248,819	$8,357,392	$9,563,648
Portfolio PGPC B2H (3)	$6,267,257	$7,287,162	$8,339,846	$9,557,784
Portfolio PGPC B2H (4)	$6,247,768	$7,401,560	$8,133,197	$9,386,236
Portfolio PGHC B2H (1)	$6,384,339	$7,386,701	$8,113,174	$9,238,667
Portfolio PGHC B2H (2)	$6,360,212	$7,232,682	$8,356,141	$9,460,037
Portfolio PGHC B2H (3)	$6,358,018	$7,270,472	$8,336,880	$9,452,539
Portfolio PGHC B2H (4)	$6,276,172	$7,379,348	$8,244,490	$9,478,369
Portfolio HGHC B2H (1)	$6,688,060	$7,603,598	$8,339,690	$9,377,658
Portfolio HGHC B2H (2)	$6,604,353	$7,410,535	$8,546,168	$9,591,880
Portfolio HGHC B2H (3)	$6,603,227	$7,447,855	$8,528,960	$9,581,960
Portfolio HGHC B2H (4)	$6,582,646	$7,563,134	$8,295,569	$9,394,863

cost run w/ impacts of non-Idaho Power resources from planning gas, planning carbon case, no B2H

cost run w/ impacts of non-Idaho Power resources from high gas, high carbon case, with B2H

As shown above, the Company modeled the costs of each portfolio under each planning future using the non-Idaho Power, broader WECC buildout corresponding to that planning future (and presence of B2H), allowing the Company to see how the different portfolios performed on a head-to-head basis under each future condition. By examining each of the Company's various resource portfolios with the non-Idaho Power resources created under the same natural gas and carbon forecasts as the planning future being examined, the Company was able to perform a consistent analysis of the relative cost of each portfolio, distinct from the costs associated with non-Idaho Power resources. This table therefore formed the basis of the Company's Preferred Portfolio selection.

G. The Preferred Portfolio is the Least-Cost Option in the Most Likely Future Scenario, and Across the Average of All Examined Futures.

In evaluating the Company's Preferred Portfolio selection, Staff asked for a robust account of how the Company selected PGPC B2H(1) as the Preferred Portfolio.[104] Due to the confusion between Tables 9.5 and 9.6, Staff relied on Table 9.5 for portfolio cost comparison, which led Staff to conclude that the Company's Preferred Portfolio performed more poorly. However, as explained above, Table 9.6 is the appropriate table to evaluate resource additions needed to meet Company-specific resource needs because this table allows for isolated comparison of portfolio costs under different planning futures (gas, carbon, and B2H) by holding the non-Idaho Power resources constant within those futures, and by using the non-Idaho Power resources associated with those futures for the cost runs. For this reason, Idaho Power relied on Table 9.6 as the basis for identifying the Preferred Portfolio.

Using Table 9.6, the Preferred Portfolio, PGPC B2H(1), was the lowest-cost portfolio in a PGPC future. It also performed well (second lowest cost) in a PGHC future. Not all futures have equal probability of occurrence and the Company considers the results of the planning forecasts to be more significant.

While there were other portfolios that performed better than the Preferred Portfolio in high gas futures, these portfolios (such as PGHC(1)) performed poorly in the more probable planning future. PGHC B2H(4) performed worse than the selected Preferred Portfolio in all but the HGPC future. Notably, no other portfolio outranked the selected Preferred Portfolio when averaging the rank across all four futures. Thus, the Preferred Portfolio was both the

[104] Staff's Final Comments at 30-31.

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first-ranked option in the planning case, as well as the best overall rank across the four potential futures.

V. SUPPLY-SIDE RESOURCES

A. Idaho Power's Action Plan Reasonably Includes a 2022 Exit Date for Valmy Unit 2.

Several parties comment on the exit timing of Valmy Unit 2 ("Valmy"). While Staff does not directly oppose early retirement of Valmy, Staff asks the Company to change its Action Item to reflect a Valmy exit in 2025 until further analysis has been performed. Staff also asks the Company to study a 2022 Valmy retirement date in the 2021 IRP.[105] CUB notes its appreciation for the analytical adjustments that led to the accelerated retirement date (2022) for this coal plant and recommends that the Commission acknowledge this action item.[106] Lastly, Renewable Northwest requests that Idaho Power conduct a transparent stakeholder process to provide input and feedback for the Valmy study.[107]

The Company appreciates Staff's perspective and recommendation to reflect a 2025 exit date for Valmy, given that more analysis will be performed. While Idaho Power's analysis in the *Second Amended 2019 IRP* supports the 2022 Valmy exit date for purposes of the IRP, the Company shares Staff's concern that more analysis is needed to support a final decision on the appropriate exit date. Crucially, Idaho Power selected the 2022 exit date in this case based on the results of the cost modeling utilized to evaluate all resource selections in the *Second Amended 2019 IRP*. In the 20-year look of the IRP, the earlier exit for Valmy shows cost savings over the 2025 exit date. Idaho Power felt it would be inappropriate to ignore this finding and, instead, use a more costly date for long-term planning purposes. As a result, Idaho Power chose to reflect the optimal exit date revealed in the IRP process, while also

[105] Staff's Final Comments at 31.
[106] CUB's Final Comments at 3 (Jan. 8, 2021).
[107] Renewable Northwest's Final Comments at 4-5.

recognizing the need to verify the cost-optimal and risk-minimizing exit date for Valmy through additional near-term analysis, including an analysis on potential system reliability impacts.

In the alternative, Idaho Power could, per the Commission's approval of Staff's recommendation, change the Action Plan to reflect a 2025 exit date for Valmy. It should also be noted that Idaho Power is required to provide 15 months' notice to its ownership partner, NV Energy, prior to exiting Valmy. Therefore, this gives the Company until September 2021 to provide NV Energy with notice of a year-end 2022 exit date. This timing will allow for the supplemental Valmy-specific analysis *and* the 2021 IRP to be complete prior to any action being taken regardless of whether the Commission determines a 2022 or 2025 exit date is appropriate within the *Second Amended 2019 IRP.*

Moving forward, the feasibility of a 2022 Valmy exit date is being further analyzed to determine near-term impacts to reliability and economics, to confirm that the timing decision will minimize costs and risks for customers. In response to Renewable Northwest's request for a transparent stakeholder process, the outline of the Valmy study scope will be presented at the 2021 Integrated Resource Plan Advisory Council ("IRPAC") meeting on February 9th, during which time Idaho Power will seek comment.

B. Idaho Power Appropriately Accounted for Jim Bridger Retirement and Fixed Operating Costs.

CUB's opening comments stated that the Company has not explained the connection between a second Jim Bridger unit retirement and the anticipated 2026 in-service date for B2H.[108] In its final comments, Staff agrees with CUB's assessment and requests further justification for this claim.[109] To clarify, exiting the second Jim Bridger unit results in a resource deficiency and, therefore, is not possible without the addition of other resources to Idaho Power's system. The Preferred Portfolio shows that this deficiency is addressed in the most

[108] CUB's Opening Comments at 8 (Apr. 2, 2020).
[109] Staff's Final Comments at 31-32.

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cost-effective way by B2H. Other portfolios allowed for the exit from the second Jim Bridger unit in 2026 with the addition of resources other than B2H, but these portfolios were not least-cost.[110]

Staff asks the Company to assess the fixed O&M cost inputs to AURORA to clarify which costs are associated with Idaho Power's versus PacifiCorp's share of the Jim Bridger plant. Staff further asks the Company to explain why these costs differ, and to what extent. Staff also asked the Company to weigh in on whether these two values should be the same in future IRPs, or whether there is a reason they should be allowed to differ.[111]

Regarding fixed costs in AURORA, Idaho Power developed the fixed costs for Idaho Power's one-third share of the plant, whereas the AURORA model vendor developed the fixed costs for PacifiCorp's two-thirds share. The Company typically does not adjust model vendor inputs for other companies' units because other companies may have different O&M versus capital upgrade methodologies or different regulatory approaches. Idaho Power remains responsible for ensuring that it is calculating its best estimate of the costs that the Company will incur. While Idaho Power appropriately relied on actual fixed O&M costs as the basis for the Company's modeling, the Company does not necessarily believe that there is only one correct method to estimate different companies' future fixed costs.

Lastly, Staff requests an update from the Company on any planned or actual negotiations with PacifiCorp regarding exit dates for Jim Bridger.[112] Idaho Power has participated in discussions with PacifiCorp on different exit dates in both companies' respective IRPs for the units at the Jim Bridger plant, but the parties have not come to terms on exit dates. The Company commits to updating the Commission with material developments as negotiations progress.

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[110] Idaho Power's Reply Comments at 38.
[111] Staff's Final Comments at 32.
[112] Staff's Final Comments at 32.

C. Idaho Power Agrees that the Exit from Boardman Cannot Be Acknowledged Because the Action Item Has Already Occurred.

CUB fully supports the Company's decision to exit from the Boardman coal plant. However, CUB believes that, since this is a completed action, it should not be acknowledged by the Commission as a part of this IRP.[113] Idaho Power agrees that the Action Item related to Boardman does not need acknowledgement as it has since passed. Idaho Power included this Action Item when the Company filed the *Second Amended 2019 IRP* in October 2020, as the December 2020 exit from Boardman had not yet occurred.

D. Idaho Power Reasonably Calculated the Capacity Value of Solar Under the Circumstances of This Case.

Staff remains concerned that Idaho Power is not in compliance with Order No. 16-326, which addressed how different companies would model the capacity value of solar in IRP proceedings.[114] As a result, Staff recommends that the Company either extrapolate from available data in order to implement the Effective Load Carrying Capability ("ELCC") method, or revert to the Company's former capacity factor ("CF") approximation method.[115]

In Idaho Power's Reply Comments, the Company provided a detailed response to Staff's concerns regarding the Company's compliance with Order No. 16-326, and explained how the Company arrived at the current approach to determining the capacity value of solar.[116] To briefly reprise, Idaho Power's previous CF approximation method was used because, at the time, the Company had no actual on-system solar data on which to base more detailed capacity calculations.[117] However, the Commission specifically noted that there was no

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[113] CUB's Final Comments at 4-5.
[114] Staff's Final Comments at 16-17.
[115] Staff's Final Comments at 17.
[116] Idaho Power's Reply Comments at 40-43.
[117] *In the Matter of Pub. Util. Comm'n of Or., Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity*, Docket UM 1719, Idaho Power's Opening Testimony of Rick Haener, Idaho Power/100, Haener/5 (Dec. 14, 2015) ("[C]urrently, there are no utility-scale solar PV projects connected to Idaho Power's system; consequently, no actual PV generation data is available[.]"); *see also* Idaho Power's Reply Comments at 41.

evidence that the CF approximation method would continue be a reasonable approach at higher solar penetration levels.[118] Indeed, the Commission anticipated that, as renewable penetration levels increased, utilities would eventually move to the ELCC calculation.

In this case, Idaho Power was faced with a situation where neither approach was tenable to serve long-term resource planning needs. As the Company went from zero solar capacity to 289 MW of capacity in a single year, and as modeled portfolios included over 1,000 MW of new solar generation, the CF approximation method was demonstrably inadequate for modeling solar's capacity value at this scale.[119] At the same time, the rapidity of the solar penetration spike meant that there was inadequate longitudinal data to perform the ELCC calculation, which requires 3-5 years of operational data.[120] As a result, Idaho Power made a good faith effort to bridge the gap between these methods, using a highly reputable variation of the ELCC calculation developed by the National Renewable Energy Laboratory ("NREL"). Again, Idaho Power presented this approach to the Company's IRPAC in December of 2018 and highlighted the transition when the Company filed the IRP Update report in January of 2019.[121]

Idaho Power recognizes 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. However, given the

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[118] *In the Matter of Pub. Util. Comm'n of Or. Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity*, Docket UM 1719, Order No. 16-326 at 6 (Aug. 26, 2016) ("No evidence was presented as to the reasonableness of the CF approximation method at higher penetration levels.").
[119] *See* Idaho Power's Reply Comments at 41.
[120] Extrapolating solar data to model more years for the analysis would be detrimental to the calculation because the outage rates of these plants and the necessary relationship between load and generation would be lost. While using such methodologies can be valuable in predicting the energy generated from a solar plant on a yearly basis, they should not be used for studies pertaining to reliability, or in this case, capacity contribution.
[121] *See* Idaho Power's Reply Comments at 42.

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Commission's own concern about the use of the CF approximation method in high solar penetration contexts, and further given the unique circumstances preventing Idaho Power from applying the traditional ELCC method, the Company complied with the intent of the Commission's order to accurately model solar's capacity value and to apply a more rigorous, nuanced approach as solar penetration increased.

To the extent that the Commission believes Idaho Power's approach to modeling solar's capacity value in this case deviated from the Commission's prior order, Idaho Power respectfully requests an exception from application of that order in this case. To be clear, Idaho Power believes that continuing to use the previous CF approximation method in this IRP, given the tremendous increase in solar penetration, would have yielded inaccurate results. Thus, the Company's approach represented a good faith effort to reconcile the need for more accurate modeling with the available data in order to adequately meet customers' long-term planning needs.

Moving forward, the dilemma that Idaho Power faced in this case will be moot. Because of the time that has now passed since the first solar plant came online in late 2016, the Company will have collected sufficient data in advance of the 2021 IRP in order to implement the full ELCC method.

E. Idaho Power Reasonably Modeled Storage Resources Given the Scale of the Company's Service Territory.

Staff asserts that the Company limited the amount of standalone storage available for selection in AURORA to 80 MW per year and limited the amount of storage that could be paired with solar to 80 MW over the entire planning timeframe. Staff concludes that these assumptions do not appear to be based on realistic technology limitations, citing an example of a 250 MW battery project in California, and asks the Company to explain the reason behind the limitations or remove these limits in future analyses.[122]

With respect to standalone storage, the Company believes there was a misinterpretation of the data in Staff's review of the AURORA database. The Company did not limit the battery storage amounts to 80 MW in the 2019 IRP. The table below shows the storage solutions and total potential for each option modeled in the 2019 IRP.

Table 7: Storage Solutions Modeled in 2019 IRP

Category	**Adoptable Resource Blocks (MW)**	**Total Potential (MW)**
Lithium Ion Battery	5	180
Lithium Ion Battery Paired with Solar	10	30
Lithium Ion Battery Paired with Solar	20	20
Lithium Ion Battery Paired with Solar	30	30
Hydro Pumped Storage	500	500
Total Lithium Ion Battery		**260**
Total Hydro Pumped Storage		**500**
Total Storage Solutions		**760**

Further, Staff's example of the 250 MW LS Gateway project in California is not a realistic example of a battery storage project for Idaho Power's modeling. Notably, the LS Gateway project is, as of August 2020, the largest battery storage project in the world, and does not represent the typical scale of battery storage projects.[123] The project's size appears to reflect the unique demands of its environment, where the 4-hours of energy storage capacity at that scale can be used to meet California's scale of demand. To be clear, California's demand exceeds that of Idaho Power's many times over. Operational battery projects used by other utilities are more commonly in the range of 5-15 MW increments[124],

[122] Staff's Final Comments at 18.
[123] PR Newswire, "LS Power Energizes Largest Battery Storage Project in the World, the 250 MW Gateway Project in California" (Aug. 19, 2020) https://www.prnewswire.com/news-releases/ls-power-energizes-largest-battery-storage-project-in-the-world-the-250-mw-gateway-project-in-california-301114983.html.
[124] Edison Electric Institute, *Leading the Way: U.S. Electric Company Investment and Innovation in Energy* Storage (Oct. 2018), available at https://www.eei.org/issuesandpolicy/Energy%20Storage/Energy_Storage_Case_Studies.pdf.

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showing that the LS Gateway project is far in excess of the norm for battery installations used by a single utility.

With respect to solar-plus-storage, Idaho Power set a threshold of 80 MW in this case. Again, given the typical size of battery storage projects, as well as the lack of any current battery storage on Idaho Power's system, the Company believed that 80 MW was a reasonable threshold in this case. However, Idaho Power agrees to evaluate higher thresholds for solar-plus-storage in the 2021 IRP.

In sum, Idaho Power views storage solutions as an important part of the Company's future and will continue to evaluate cost-effective storage solutions in the 2021 IRP.

F. Idaho Power Agrees to Model Hybrid Resources in Separate Categories in the 2021 IRP.

Renewable Northwest urges the Company to study emerging flexible capacity resources, including hybrid resources such as wind-plus-battery and solar-plus-battery options.[125] Idaho Power appreciates Renewable Northwest's recommendations and agrees that it is important to evaluate hybrid resources in separate resource classes with multiple defined dispatch characteristics. Indeed, during the manual adjustment process, Idaho Power included solar-plus-battery in a separate category from standalone solar (though separate categories were not used in the AURORA modeling process). For the 2021 IRP, Idaho Power will model separate resource classes to address these concerns.

G. Idaho Power's Use of Placeholder Flexible Resources is Consistent with the Company's 2045 Clean Energy Goal.

Staff and Renewable Northwest note that the Company's Preferred Portfolio currently includes acquisition of a new gas-fired plant in 2031, which would be inconsistent with Idaho Power's goal to serve customers with 100 percent clean energy by 2045.[126] Staff asks the

[125] Renewable Northwest's Final Comments at 3.
[126] Staff's Final Comments at 19-20 and Renewable Northwest's Final Comments at 4.

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Company to clarify if Idaho Power intends to build a gas plant in 2031, or intends to meet its 2045 clean-energy goals—and, if the latter is true, asserts that the Company must modify its Preferred Portfolio so it "accurately reflects the Company's intentions."[127]

As an initial matter, Idaho Power remains focused on its goal of 100 percent clean energy by 2045. As Idaho Power has previously explained, the new natural gas generation identified in the Preferred Portfolio is intended as a placeholder for flexible resources that can meet system needs. This "surrogate resource" approach has also been taken by Portland General Electric ("PGE") in that company's IRP, with the understanding that ongoing technology development and cost changes will ultimately determine what the flexible resource will be.[128] Thus, while there is a superficial incongruity between the Company's 2045 clean energy goal and the current least-cost/least-risk Preferred Portfolio, the Company fully anticipates technology advancements and associated cost declines will facilitate the replacement of natural gas with clean, flexible resources.[129]

Idaho Power's use of natural gas facilities as placeholder resources is also consistent with the IRP's least-cost/least-risk planning requirements. On a levelized basis, natural gas generation is currently the least-cost and most reliable form of dispatchable generation. While Idaho Power is fully committed to achieving its 2045 goal, the Company is equally committed to least-cost planning—and, today, the resource that allows Idaho Power to balance intermittent renewable energy resources in a reliable and cost-effective manner is natural gas. Idaho Power would be remiss if it artificially selected more costly alternatives as part of its least-cost Preferred Portfolio. Fortunately, as the solar and wind markets have demonstrated, today's technology prices will not reflect those a decade from now. Idaho Power is motivated

[127] Staff's Final Comments at 20.
[128] *In the Matter of Portland Gen. Elec. Co., 2019 Integrated Resource Plan*, Docket LC 73, PGE's 2019 IRP at 70 (July 19, 2019).
[129] Staff's Final Comments at 19-20 and Renewable Northwest's Final Comments at 4.

to find a carbon-free solution, and will continue to thoroughly evaluate clean, flexible resource options in all future IRPs.

To be clear, Idaho Power does not seek acknowledgment of a specific decision to build a natural gas plant in 2031; the Company seeks acknowledgment of its Action Plan, which was developed with the understanding that future flexible generation capacity will be necessary in 2031, and near the tail-end of the Company's 20-year planning period. The specific generation technology of these flexible resources does not impact the Company's Action Items.

As noted above, the challenge of balancing least-cost planning with a rapidly evolving technology landscape, coupled with firm commitments to pursue clean energy, is not unique to Idaho Power. While some companies, such as PGE, have explicitly designated resources in their preferred portfolios as "flexible resources"—with the understanding that the specific generation source will be identified closer to the development date—Idaho Power used the current low-cost option of natural gas generation as the placeholder resource, as natural gas generation represents the type of capacity and renewable energy integration capability needed at that time. As an alternative to modeling a natural gas plant, the Company is also amenable to designing a placeholder resource with the same flexibility as a natural gas plant, but without the emissions, and clearly labeling it as a "placeholder flexible resource."

H. Idaho Power Appropriately Modeled Wind Resources' Costs and Capacity Contribution but Agrees to Update These Values in the 2021 IRP.

Staff expresses concern about the price of wind resources in the Company's *Second Amended 2019 IRP*. Specifically, Staff recommends that, in the 2021 IRP, the Company model the Production Tax Credit ("PTC") for wind to the extent it is technically achievable by the Company to revise its Wyoming wind cost inputs.[130]

[130] Staff's Final Comments at 21.

Staff's comments appear to assume that the reason wind resources were not selected in the *Second Amended 2019 IRP* Preferred Portfolio was largely due to cost assumptions that could be mitigated through offsetting PTC benefits. However, a larger factor was wind's limited contribution to meeting the Company's summer peak. Additionally, at the time Idaho Power modeled the 2019 IRP, the PTC was assumed to expire in 2020, though the PTC has since been reauthorized to extend through 2021.[131] To address Staff's recommendations, Idaho Power's 2021 IRP will update wind resources' capacity contribution to peak (in addition to similar updates for solar), and will model the PTC for wind to the extent it is technically achievable.

More generally, while Idaho Power appreciates Staff's support for using offsetting customer benefits as a factor in resource planning, the Company notes that Staff's comments in this case are inconsistent with Staff's position—and the Commission's recent commentary—in the context of cost recovery. For example, 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.[132] While the Commission did not impose specific cost recovery limitations in that case, the Commission suggested that it might reopen and condition recovery of such prudently incurred costs in a future proceeding.[133]

More recently, the Commission took a similar approach in PacifiCorp's general rate case, docket UE 374, expressing the intent to limit future power cost recovery for wind projects

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[131] *See* Further Consolidated Appropriations Act, 2020, Pub. L. No. 116–94, 133 Stat. 2534, 3226 (Dec. 20, 2019) (Division Q includes the Taxpayer Certainty and Disaster Tax Relief Act of 2019).
[132] *In the Matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause (Schedule 122) (Wheatridge Renewable Energy Farm)*, Docket UE 370, Staff's Reply Brief at 3 (July 15, 2020) (stating that the wind project "was largely driven[,] not by a near-term resource need, but rather, long-term economic benefits due to time-limited tax credits").
[133] Docket UE 370, Order No. 20-321 at 5 (Sept. 29, 2020) ("Though we find that the selection of the Wheatridge project was prudent, . . . this does not preclude further ratemaking adjustments related to the recovery of project costs for Wheatridge to appropriately allocate performance risks.").

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timed to take advantage of PTCs.[134] Given the Commission's and Staff's prior regulatory treatment of wind projects timed to maximize PTC benefits, Idaho Power would hope for clarification that the Company would not be penalized for complying with Staff's request by, for instance, limiting Idaho Power's future ability to recover prudently incurred costs.

I. Idaho Power Correctly Modified Its Modeling of Natural Gas Peaker Plants to Account for Start-Up Costs.

STOP B2H raises concerns over Idaho Power's decision to incorporate start-up costs in the modeling for natural gas peaker plants—a change identified in the IRP review process and applied in modeling the *Second Amended 2019 IRP.*[135] In support of the change, the Company provided the following explanation in the 2019 IRP Review Report, which was submitted alongside the *Second Amended 2019 IRP*:

> Natural Gas Peaker Plant Start-Up Costs: The maintenance costs associated with natural gas peaker plants were captured only as a variable cost applied directly to the run time of the unit. Startup costs were not included, which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected. After identifying the issue, startup costs were entered, resulting in a reduction in peaker dispatch and more accurately reflecting a logical and expected outcome.[136]

STOP B2H claims that including plant start-up costs means that Idaho Power deliberately adjusted the AURORA model to justify future gas replacements, as alternatives to the more expensive peaking plants.[137] STOP B2H further states that this modification goes against Executive Order 20-04, and that the Commission should therefore refuse to acknowledge this IRP.[138]

STOP B2H is mistaken. Modeling for natural gas peaker plants was adjusted to more accurately reflect the real costs incurred when dispatching a peaker plant. This change was

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[134] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 374, Order No. 20-473 at 54 (Dec. 18, 2020) ("[W]e will continue to look at [the wind projects'] performance and value in future power cost proceedings.").
[135] STOP B2H's Final Comments at 26-29.
[136] Second Amended 2019 IRP, Review Report at 6.
[137] STOP B2H's Final Comments at 29.
[138] STOP B2H's Final Comments at 29.

prompted by the Company's review process, during which time the Company discovered that gas peaker plants were not dispatching as expected. Faced with this anomaly, the Company's subject matter experts carefully reviewed natural gas peaker plant O&M costs—specifically start-up costs—then updated, tested, and documented the adjustment to the model. Rather than modifying the Company's AURORA model to justify new gas facilities, the Company's more nuanced analysis *disfavors* natural gas peaking plants by accounting for the more costly start-up process associated with peaking dispatch.

VI. DEMAND-SIDE RESOURCES

Demand-side resources, or demand-side management ("DSM") resources, including energy efficiency ("EE") and demand response ("DR"), are important aspects of Idaho Power's resource planning process and were included in the 2019 IRP. Idaho Power has a mature portfolio of both EE and DR programs available to all customer sectors, and the Company has achieved steady gains in DSM penetration over time. Staff and STOP B2H address the Company's efforts around EE, DR, and Time-of-Use ("TOU") rate offerings, which the Company addresses in turn.

A. Energy Efficiency

1. Idaho Power Remains Committed to Pursuing Cost-Effective EE and Will Further Report on Its Response to Action Item 9.

Staff's final comments indicate that the Company's response to Action Item 9,[139] in the Company's Reply Comments, was not as direct nor as thorough as Staff had hoped. To remedy this, Staff requests that, as part of the Company's 2019 IRP Update, the Company review all piloted measures that the Energy Trust of Oregon ("ETO") has undertaken in the

[139] Action Item 9 is a reference to the Action Plan of the Company's 2017 IRP, which stated "continue the pursuit of cost-effective energy efficiency." The Commission acknowledged the Action Item with the following modification: "In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology." (Order No. 18-176 at 16.)

last three years 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.[140]

Idaho Power periodically reviews ETO's and other utilities' activities to identify new cost-effective measures or programs that might benefit customers in the Company's service area and is amenable to providing a review of how ETO's piloted measures compare to the Company's existing programs. The Company recognizes that sharing the specific results of the analysis recommended by Staff may help inform potential program changes in the Company's EE portfolio. Therefore, the Company commits 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. With respect to the timing of reporting to the Commission, because Idaho Power is seeking a waiver from the need to file an IRP Update in this case (see below) the Company commits to report on this review and the feedback from the EEAG in the 2021 IRP.

Idaho Power is committed to the pursuit of cost-effective EE, and that commitment has been demonstrated by the Company's sustained efforts and program activity. Idaho Power has also expanded the IRP process to include an EE subcommittee as part of the 2021 IRP, which includes a variety of stakeholders, including Staff and STOP B2H, with the purpose of helping to guide the Company's approach to including EE potential in the 2021 IRP.

2. <u>EE Savings Have Grown Steadily Over Time.</u>

STOP B2H claims Idaho Power's energy savings have remained relatively static since 2015 and actually have declined since 2010.[141] STOP B2H is incorrect. In 2019,

[140] Staff's Final Comments at 9-10.
[141] STOP B2H'S Final Comments at 45.

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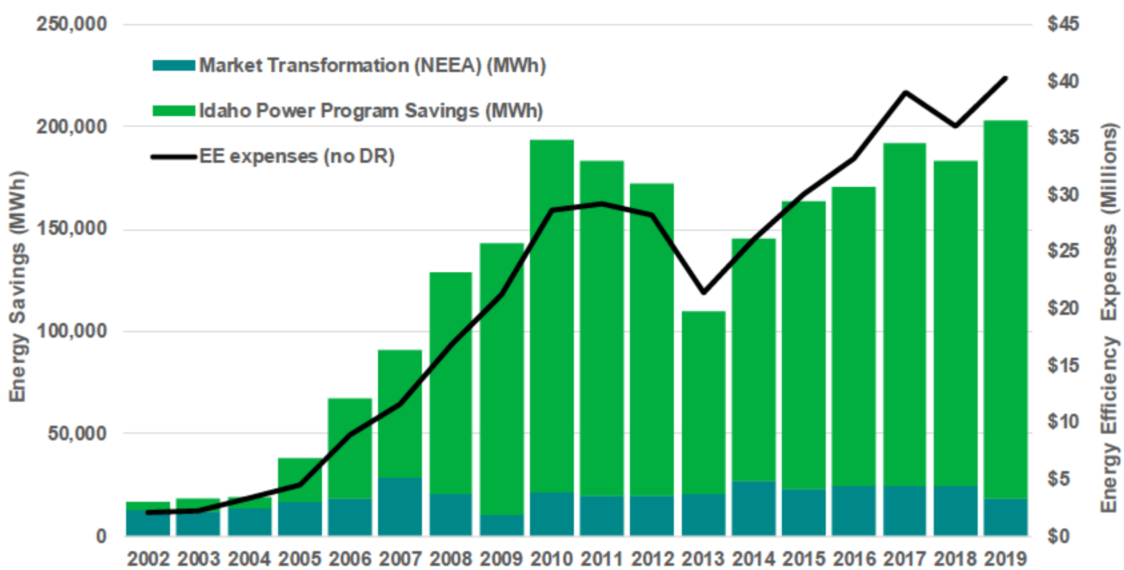
Idaho Power achieved its highest EE savings since the Idaho Energy Efficiency Rider was established in 2002.[142] Idaho Power has seen steady growth, with energy savings growing from 162,533 MWh in 2015 to 203,041 MWh in 2019—a 25 percent increase since 2015. These savings were achieved over a period with significantly declining DSM alternate costs, which decreased by more than one-half between the 2011 IRP and 2019 IRP. This data point proves that the Company has continued to support cost-effective EE even when energy savings assumptions for a variety of measures reduced over time. Figure 2 is from the Company's *2019 DSM Annual Report,* highlighting savings achievement from 2002 through 2019 and, in particular, showing the steady growth in savings achievement since 2013.

Figure 2: Annual energy savings and energy efficiency program expenses, 2002–2019 (MWh and millions [$])[143]



Further, the following chart from the NWPCC illustrates regional trends in EE from 2004 to 2019 and shows that, not only has regional EE savings potential decreased since

[142] *In the Matter of Idaho Power Company's Request for Cost-effectiveness Exceptions for Specific Demand-Side Management Electric Measures and Programs*, Docket UM 1710, Idaho Power Company's 2019 Demand-Side Management Report at 1 (Apr. 1, 2020).
[143] Docket UM 1710, Idaho Power Company's 2019 Demand-Side Management Report at 5.

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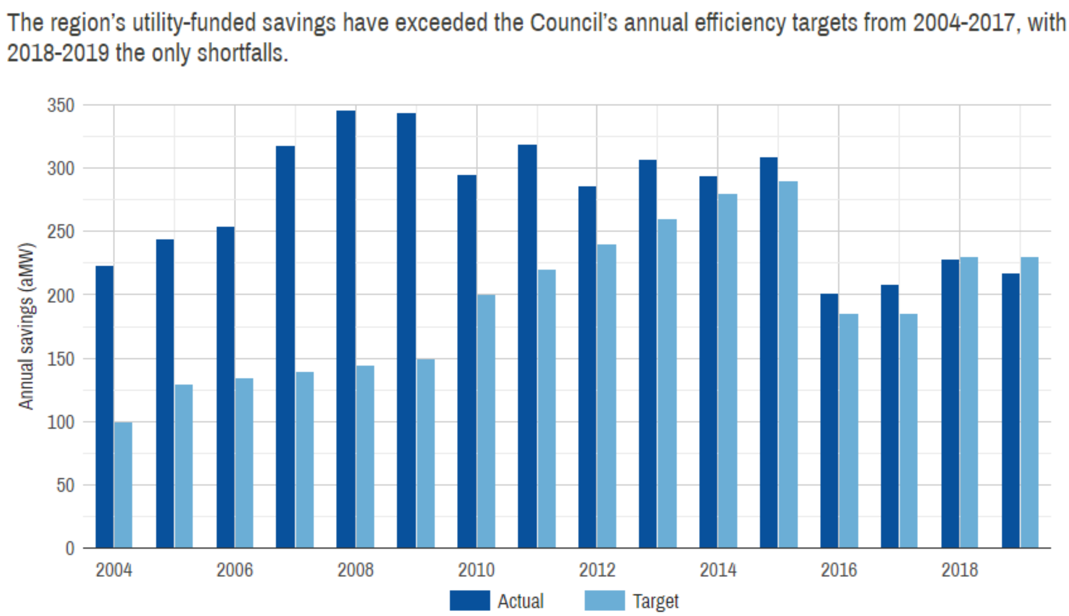
2016, but the regional savings achieved by utilities have remained the same or declined since 2010. In contrast, Idaho Power's savings have re-bounded since 2013, with savings steadily increasing in recent years, unlike the rest of the region.

Figure 3: Northwest Power Council's Regional Energy Efficiency Targets[144]



3. <u>Idaho Power's EE Targets Are Consistent with Industry Standards.</u>

STOP B2H further asserts that the Company's EE targets are set too low, thereby impacting resource forecasting needs.[145] In response to stakeholder feedback and the Company's commitment to pursue all cost-effective EE, Idaho Power modified its EE potential as part of the 2019 IRP to include utilization of the AURORA model. The model could then screen and potentially select additional EE bundles, above the EE amounts already identified as achievable economic potential in the third-party Potential Study (described above and in more detail below). The AURORA model did not select any of the higher-cost EE bundles.

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[144] NWPCC, *What have the region and Council achieved?* (2021), available at: https://www.nwcouncil.org/energy/energy-topics/energy-efficiency.
[145] STOP B2H's Final Comments at 46.

The Company's historical approach to EE savings potential in the IRP is consistent with industry standards. The achievable economic potential is based on a rigorous assessment of the available EE potential in Idaho Power's service area, conducted by an experienced third-party consultant using industry-standard methods. For the 2019 IRP and the forthcoming 2021 IRP, Idaho Power has contracted with Applied Energy Group ("AEG"), which has significant experience and expertise in developing EE potential studies. AEG has done this precise work for many utilities and also has prior experience developing potential studies for Idaho Power.

To perform the Potential Study analysis for the 2019 IRP, AEG used the following approach:

(1) Performed a market characterization to describe sector-level energy use for the residential, commercial, industrial, and irrigation sectors for the base year of the study. This included using Idaho Power data and other secondary data sources, such as data from the U.S. Energy Information Administration ("EIA").

(2) Developed a baseline projection of energy consumption and peak demand by sector, segment, and end use for the time period of the study.[146]

(3) Defined and characterized several hundred EE measures to be applied to all sectors, segments, and end uses.

(4) Estimated technically achievable potential of EE measures in terms of energy and peak demand impacts from those measures for the time period of the study.

(5) Determined the achievable cost-effective EE using avoided cost information from Idaho Power as the threshold value of EE.

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[146] Sector refers to the customer type (*i.e.*, residential, commercial, industrial, irrigation), while segment refers to the customer electricity type (*e.g.*, home type, school, retail or industrial Standard Industrial Classification code).

The Company is expanding on its experience with EE bundling and EE selection through AURORA as part of the 2021 IRP. Initial discussion with stakeholders through the EE subcommittee indicates a preferred approach of including achievable economic potential from the Potential Study with additional, selectable-by-AURORA bundles. Idaho Power looks forward to working closely with the IRPAC to further refine how EE potential is modeled in the 2021 IRP.

B. Demand Response

1. The Cost of Future DR Will Be Re-Evaluated in the 2021 IRP.

Staff asks for further explanation on the Company's levelized cost of capacity ("LCOC") for DR resources in the 2019 IRP. Staff suggests modeling expanded DR based on real programmatic approximations or, alternatively, using LCOC estimates to represent incremental increases of DR.[147] Idaho Power appreciates Staff's concurrence that it may be unreasonable to assume expanded DR could be added at the same LCOC as existing resources. The Company detailed its assumptions for the LCOC of DR in response to Staff's Data Request 41 and again in the Company's Reply Comments. The Company explained that DR, as a customer-based program, is difficult to simulate with respect to future costs, particularly more than a decade into the future.[148] The Company understands Staff's perspective and commits to providing a detailed explanation of any cost estimates used in the LCOC for DR in the 2021 IRP.

2. Idaho Power is Appropriately Procuring DR to Meet Peak Capacity Need.

STOP B2H continues to note that Idaho Power's DR capacity has decreased since 2012 and claims that this decrease demonstrates that the Company's DR efforts are "half-hearted" and that the Company seeks to avoid clean-energy commitments.[149]

[147] Staff's Final Comments at 14.
[148] Idaho Power's Reply Comments at 59.
[149] STOP B2H's Final Comments at 48.

While STOP B2H is correct that DR capacity decreased since 2012, STOP B2H overlooks the reason for the decrease. To be clear, Idaho Power's DR programs were designed specifically to avoid or delay the need to build new supply-side peaking resources within very limited peak hours and days. In 2012, the Company's analysis showed that there would be no capacity deficit in peak hours over the next several years.[150] Idaho Power therefore temporarily suspended its DR programs to avoid spending customer money on a resource that was not needed. In a subsequent proceeding opened to examine the Company's DR programs, the parties and the Commission agreed that the Company would not add new DR programs in years when the Company does not anticipate peak-hour capacity deficits.[151] While STOP B2H criticizes the Company for relying on the 2013 settlement agreement, the Company believes that its compliance is appropriate.[152] Idaho Power's would like to point out that its 2019 DR capacity as a percent of system peak remains significantly higher than most utilities in spite of a decrease. Figure 4 below compares Idaho Power's DR capability compared to other investor-owned electric utilities.

[150] *In the Matter of Idaho Power Company, Staff Evaluation of the Demand Response Programs*, Docket UM 1653, Order No. 13-482, Appendix A at 1 (Dec. 19, 2013).
[151] Order No. 13-482 at 3.
[152] STOP B2H's Final Comments at 45; Order No. 13-482 at 3.

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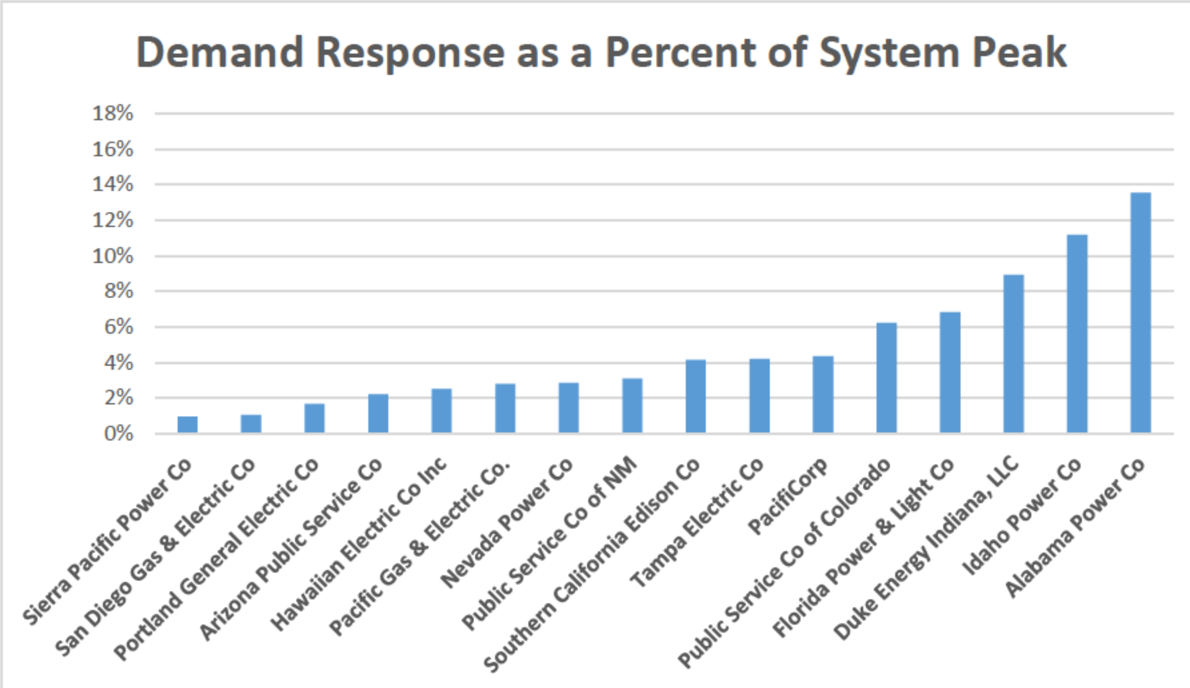
Figure 4: Demand Response as a Percent of System Peak[153]



Finally, STOP B2H protests the lack of new DR for 10 years based on the Preferred Portfolio.[154] In the *Second Amended 2019 IRP*, a capacity deficit is not identified until 2026, and that deficit is met through a resource with broader availability than DR. The Company's IRP analysis indicated that, with the current level of DR on the system (11 percent of Idaho Power's all-time system peak), additional DR capacity does not serve as the lowest-cost resource until 2030.[155]

3. Idaho Power Will Continue to Explore the Potential for Future DR Programs.

CUB generally supports the Company's change in DR modeling, which modified the treatment of DR from being the "lender of last resort once the Company's reserves

[153] U.S. Energy Information Administration, *Annual Electric Power Industry Report, Form EIA-861 detailed data files* (Oct. 6, 2020), available at: https://www.eia.gov/electricity/data/eia861/. Please note that the figure includes data from investor-owned electric utilities only.
[154] STOP B2H's Final Comments at 45-46.
[155] Second Amended 2019 IRP at 15.

were in deficit," to being modeled as "a resource to offset peak load[.]"[156] However, CUB recommends that the Company explore winter DR programs to meet winter peak loads.[157]

While the Company appreciates CUB's recommendation in principle, on Idaho Power's system, meeting summer capacity deficits generally means that winter capacity deficits do not exist. That said, if a capacity deficit develops with respect to the Company's winter peaks, Idaho Power is open to future modifications of its DR analysis and balancing assumptions to reflect these changing needs.

CUB also notes that DR has the potential to provide ancillary services that may be worth evaluating in the future, particularly as Idaho Power exits thermal generation and integrates more variable energy resources.[158] Idaho Power has previously reviewed the potential for its existing DR programs to provide ancillary services, and filed a report with the Commission as part of evaluating the Company's DR programs in 2014.[159] This review determined that current DR programs could be used only for the non-spinning portion of the Company's Contingency Reserve Obligations ("CRO"). The report concluded that the operational and compliance risks outweigh the benefits of using DR as CRO for the following reasons:

(1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and cover program costs;

(2) the risks for failure to meet NERC standards is far greater than the economic benefit that might be achieved;

(3) the period of testing that would be required to provide operational certainty of compliance with NERC and WECC requirements would necessitate carrying

[156] CUB's Final Comments at 3.
[157] CUB's Final Comments at 4.
[158] CUB's Final Comments at 4.
[159] Docket UM 1653, Idaho Power's Demand Response as Operating Feasibility Report (Sept. 30, 2014).

substantially more than the reserves actually needed for contingency, at an additional cost to all customers; and

(4) the number of CRO events would put too heavy a strain on the DR participants, thus risking participation in the Company's DR Programs.[160]

Given that the central reliability and cost concerns in this report remain true today, the report's conclusions are likely still valid. However, DR programs under extreme peak times can reduce system load, which allows other resources to meet reserve obligations. Thus, Idaho Power is not opposed to investigating the use of DR for certain ancillary services in the future.

Lastly, CUB recommends that the Company develop a draft plan for potential DR programs and include the plan in its future DSM report or as part of its VER Integration Study.[161] Idaho Power believes the appropriate place to discuss potential DR programs is in the IRP. The Company's annual DSM report is a tool for reporting on Idaho Power's current accomplishments and near-term activities, and the purpose of the VER Integration Study is to analyze the cost to integrate resources, not identify specific resources solutions. Thus, as part of the 2021 IRP, the Company will analyze the capability of DR to meet possible capacity needs and commits to report on that analysis in the IRP.

C. Idaho Power Supports Evaluating Time-of-Use Programs in a Rate Case or Other Rate-Related Proceeding.

Staff requests an update on the Company's Oregon Residential Time-of-Day ("TOD") Pilot Plan. Specifically, Staff asks Idaho Power to include an update on the number of participants, costs, peak capacity reduction by season, and a proposal for an alternate venue to report pilot results.[162]

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[160] Docket UM 1653, Idaho Power's Demand Response as Operating Feasibility Report at 1.
[161] CUB's Final Comments at 4.
[162] Staff's Final Comments at 15.

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By way of background, the Company implemented an optional, voluntary TOD pilot pricing plan in June 2019 that is available to residential customers residing in the Company's Oregon service area. The intent of the TOD Pilot Plan was to introduce an optional pricing offering for Oregon residential customers that includes a seasonal and time-differentiated rate design reflective of the cost to serve. Following Commission approval to implement the plan, Idaho Power marketed the program with postcard mailers and also created a rate comparison tool that is available on My Account. To date, there are three customers participating in the 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,[163] Idaho Power believes it is 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 believes it is 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.

VII. FORECASTS

A. Idaho Power Appropriately Models Qualifying Facility Resources.

REC's final comments covered several key themes, including clearing up assumptions related to the Company's Cogeneration and Small Power Production ("CSPP") forecast, which includes estimated generation from Public Utilities Regulatory Policies Act ("PURPA") Qualifying Facilities ("QF"); requests for additional detail on the CSPP forecast assumptions

[163] *In the Matter of Pub. Util. Comm'n of Or., Investigation into Distribution System Planning*, Docket UM 2005, Order No. 20-485, Appendix A at 1 (Dec. 23, 2020).

for the next IRP; and a request for resolution on providing capacity payments for QFs renewing their Energy Sales Agreement ("ESA").[164]

In response to REC's concerns, Staff recommends that the Company describe what specific wind repowering developments would cause the Company to change its wind QF renewal assumptions. Staff notes that there is risk inherent in assuming that none of the wind contracts will renew.[165] For the 2021 IRP, Staff requests the Company incorporate sensitives related to wind QF renewals.[166]

1. Idaho Power Will Provide Additional Detail Related to its QF Modeling Assumptions.

Idaho Power has been consistent across multiple IRPs regarding the development and application of the Company's Cogeneration and Small-Power Producers ("CSPP") forecast. The CSPP forecast includes all QF generation facilities under ESAs and non-PURPA projects delivering generation to the Company pursuant to utility PPAs. Within the CSPP forecast, Idaho Power assumes that when QF ESAs expire they will be replaced with new ESAs. This assumption applies to all resource types except for wind. That said, the Company will include more detail around its assumptions in the 2021 IRP.

2. Idaho Power Appropriately Does Not Assume that Wind QFs Will Renew.

Both Staff[167] and REC[168] express concern over the Company's assumptions for wind QFs, specifically that wind QFs will not renew their ESAs. Specifically, REC asks the Company to provide a clearer analysis and narrative explanation regarding the basis for its QF renewal assumptions in future IRPs.[169]

[164] REC's Final Comments (Jan. 8, 2021).
[165] Staff's Final Comments at 6.
[166] Staff's Final Comments at 8.
[167] Staff's Final Comments at 6-7.
[168] REC's Final Comments at 6-7.
[169] REC's Final Comments at 5.

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Idaho Power considered a range of factors before establishing, for long-term modeling purposes, that wind QFs could not be assumed to renew their contracts upon expiration. These factors include the high cost of repowering wind facilities, reductions (and the potential elimination) of wind project tax credits, and the relatively high wind integration costs. At this time, Idaho Power has also not experienced a wind QF expiration, and so does not have experience available to suggest that wind QFs will seek to renew their contracts. In contrast, Idaho Power has entered into more than 35 new replacement ESAs for existing hydro, biomass, and cogeneration QFs that had been delivering generation to Idaho Power under previous ESAs.

To support the likelihood of repowering, Staff notes that PacifiCorp has been pursuing repowering at certain wind facilities.[170] While this is true, Idaho Power does not have inside knowledge of PacifiCorp's reasoning and the Company has no reason to believe that PacifiCorp's actions will extrapolate squarely onto QFs.

Idaho Power continues to believe its assumptions regarding replacement contracts in the CSPP forecast are reasonable. The Company understands and recognizes that repowering of wind facilities occurs in the industry. However, until Idaho Power has evidence to support intent to or interest in repowering wind QFs, the Company does not consider it appropriate to assume wind QF replacement ESAs in its CSPP forecast. However, as wind replacement ESA information becomes available, Idaho Power is open to revising its assumption for QF wind replacement ESAs in future IRPs. And, in response to Staff's suggestion, Idaho Power will perform sensitivity analysis in its next IRP pertaining to wind replacement assumptions to evaluate the impacts on resource planning.

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[170] Staff's Final Comments at 6.

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3. Idaho Power Appropriately Does Not Include Speculative New QF Projects.

REC also questions if new QFs should be included in the Company's CSPP forecast.[171] New QF development is not appropriate to include in the IRP, as development of QF resources is highly speculative. Not only is QF development outside of Idaho Power's control, but there is no reliable means of forecasting future QF development.

4. Idaho Power has Complied with Commission Directives in Order No. 16-174.

Next, REC states that Idaho Power has not complied with the Commission's directives in Order No. 16-174.[172] Specifically, REC claims that "Idaho Power did not comply with the Commission's order to address the value of deferred capacity that occurs when QFs renew their contracts."[173]

REC is plainly incorrect because Idaho Power does, in fact, account for QF contract renewals to determine the Company's deferred capacity. As REC recognizes elsewhere in its comments, Idaho Power includes QF generation in its CSPP forecast.[174] This forecast is then used as an input to the IRP. Generation from QFs is included in the Company's generation resource estimates, and capacity and energy contributions from QFs are included in the determination of capacity sufficiency/deficiency.

5. QF Capacity Payment Concerns Should Be Considered in a Generic Proceeding.

Lastly, REC appears to claim that Idaho Power's implementation of Oregon's avoided cost methodology fails to adequately compensate QF's for their capacity contribution.[175] As Staff correctly notes,[176] the compensation due to QFs is not within the scope of an IRP

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[171] REC's Final Comments at 4-5.
[172] REC's Final Comments at 4.
[173] REC's Final Comments at 2.
[174] REC's Final Comments at 3 ("By assuming that these contracts will renew, Idaho Power is deferring other resources that it would otherwise need to acquire.").
[175] REC's Final Comments at 3-4.
[176] Staff's Final Comments at 7 ("Staff agrees with the Company's Reply Comments that this issue should instead be addressed in UM 2000.").

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proceeding, as it is a component of PURPA avoided costs. Rather, REC's concerns should be addressed in a generic PURPA proceeding, such as docket UM 2000.

B. Idaho Power's Load Forecasts Are Reasonable and Robustly Supported.

Both Staff and STOP B2H present closing comments regarding the Company's load forecasting. Generally, Staff supports the Company's approach to modeling weather-related load impacts, EV forecasting, and the use of long historical time series for input data.[177] However, Staff expresses concern regarding some of the details of the Company's modeling, and particularly how the Company accounts for forecasting error.

Staff also encourages the Company to present the impacts of the pandemic-related recession on long-term load growth as part of the 2021 IRP. Idaho Power agrees to this proposal.

1. <u>Idaho Power Continues to Improve Its Long-Term Models Based on Stakeholder Feedback and Will Conduct a Workshop on the Issue.</u>

Staff questions how the Company addresses potential non-stationarity in long-term load forecasting.[178] Previously, Staff suggested that the Company's forecasts could be improved by using the Auto Regressive Integrated Moving Average ("ARIMA") models, which function very similarly to the Company's current Ordinary Least Squares ("OLS") approach, but include three additional terms.[179] Idaho Power's Reply Comments committed to using ARIMA error testing to test for after-the-fact stationarity, and to explore other statistical methods as well.[180] However, the Company also noted that ARIMA models can introduce additional risk of inaccuracy and interpretability of moving averages throughout the forecast period without thorough testing. In response, Staff asks Idaho Power to identify in Final Comments what statistical method the Company will use to evaluate whether ARIMA models

[177] Staff's Final Comments at 5-7.
[178] Staff's Final Comments at 5.
[179] Staff's Opening Comments at 19 (Apr. 1, 2020).
[180] Idaho Power's Reply Comments at 62.

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can reduce forecast error. Staff also urges the Company to conduct a workshop to present a statistical method addressing this issue for the 2021 IRP.

Since the Company filed Reply Comments, Idaho Power has continued to assess possible improvements to its load forecasting analysis. The Company remains committed to using ARIMA error testing and to explore other statistical models and looks forward to hosting a forthcoming workshop to convey these improvements.

Finally, Staff notes that the Company's load forecasting models include indicator variables, and recommends that Idaho Power "explore using a metric like the Akaike Information Criterion (AIC) because it penalizes model complexity and helps select a model that is flexible for future data."[181] As discussed previously with Staff, prospective improvements with respect to indicator variables within the Company's residential models and out-of-sample testing results are slated to be included in future IRPs, as well as the relationship of the included stochastic runs and load forecast sensitivities due to economic variability.

2. <u>Econometric Models Remain Appropriate for Use in Long-Term Planning.</u>

STOP B2H urges the Company to abandon econometric modeling for a simpler, more accessible approach. STOP B2H suggests alternate methodologies, such as spline interpolation and non-linear regression that, according to STOP B2H, would reduce the error in the Company's forecasts.[182] While Staff does not support STOP B2H's request, Staff recommends that the Company improve its explanation for why previous load forecast models were inaccurate, and how the new models are improving.[183]

[181] Staff's Final Comments at 8.
[182] STOP B2H's Final Comments at 39-43.
[183] Staff's Final Comments at 5.

The Company has taken strides to incorporate considerations and feedback with respect to its modeling processes, as noted by Staff.[184] An important consideration for any modeling effort is accounting for the long-term analytical nature of the IRP. For example, a linear regression model minimizes the potential to inaccurately extrapolate near term-trends—such as short-term variability associated with irrigation demand, for example, or unforeseen changes in economic conditions—into the long-term future. Additionally, models such as linear regressions are effective at considering longer-term rates of change. The Company's present forecast methodology provides a long-term planning framework that aligns retrospective comparisons to weather-adjusted growth, while accounting for the specific factors that impact Idaho Power's future load.

Thus, while Idaho Power appreciates STOP B2H's comments and suggestions, the Company continues to believe that the inferred econometric models are the best available means for long-term load growth forecasting, with their ability to factor in both a rich history of data and to account for a range of factors impacting load growth. These models are the industry standard for long-term load forecasting in the IRP context.

3. Weather-Adjusted Sales Are Increasing.

STOP B2H asserts that the increase in residential population has been perfectly matched by a decrease in average residential use, resulting in "flat sales for thirteen years."[185] STOP B2H is incorrect, as demonstrated by clear data. Idaho has been the fastest growing state for three consecutive years, as determined by the U.S. Census Bureau.[186] Evidence of this trend can be found in the Company's weather-adjusted sales to the residential class, which has grown in the range of approximately 1 to 2 percent per year in recent years (see

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[184] Staff's Final Comments at 4.
[185] STOP B2H's Final Comments at 35-36.
[186] *See* U.S. News, "America's Fastest-Growing States" (Dec. 22, 2020), available at: https://www.usnews.com/news/best-states/slideshows/these-are-the-10-fastest-growing-states-in-america.

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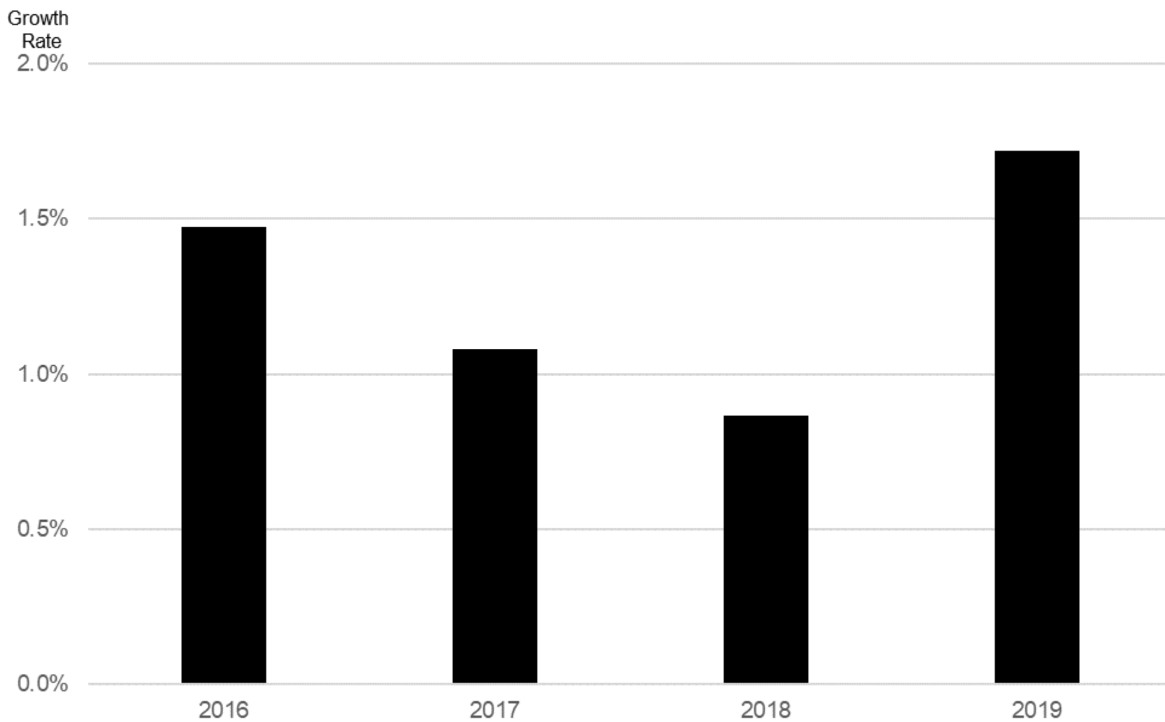
Figure 5 below). Beyond the net residential-related growth in Idaho Power's service area, the foundational agricultural base of the Company's service area continues to grow.

Figure 5: Residential Annual Weather-Adjusted Sales Growth



VIII. OTHER

A. Idaho Power's Carbon Emissions

In its final comments, STOP B2H claims that Idaho Power is distorting its carbon dioxide ("CO_2") emissions history while hiding recent large increases in the carbon intensity of existing gas-fired resources. STOP B2H questions the baseline date for the Company's voluntary emissions reduction goal and claims that the Company has quietly embarked on a high-carbon operating strategy for its gas-fired resources as a result of trading in the Energy Imbalance Market ("EIM").[187] These claims are quite simply incorrect.

[187] STOP B2H's Final Comments at 22.

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1. The Baseline Year for Idaho Power's Corporate Emissions Reduction Goal Was Appropriately Set.

By way of background, in September 2009, IDACORP's and Idaho Power's boards of directors voluntarily approved guidelines that established a goal to reduce the CO_2 emissions intensity of Idaho Power's utility operations. The initial goal was to reduce emissions 10 to 15 percent from 2005 levels.

STOP B2H states that "Idaho Power's choice of calendar year 2005 as the base year against which progress toward carbon reduction is measured is duplicitous."[188] Idaho Power strongly disagrees. On the contrary, the date was selected consistent with multiple GHG-reduction frameworks and pieces of legislation. Perhaps the most notable was the American Climate and Energy Security Act of 2009 (more commonly known as the Waxman-Markey Bill), which would have been implemented nationally and required, among other things, a 17 percent reduction by 2020 from 2005 levels.[189] At the time Waxman-Markey was written, and in subsequent national and state-level efforts to select a baseline target for GHG reductions, the 2005 date was selected not arbitrarily but because that year was a generational peak for national GHG emissions.[190] It was then, and remains, a logical basis by which to set meaningful emissions reduction targets. Considering the historical context, Idaho Power's initial emissions reduction goal of 15 percent below 2005 levels mirrors other nationally debated targets.

STOP B2H also states that the biggest indicator of emissions for Idaho Power "is the amount and shape of the hydro runoff."[191] Idaho Power has always stated that because Idaho Power's CO_2 emissions intensity fluctuates with stream flows and production levels of

[188] STOP B2H's Final Comments at 21.
[189] American Climate and Energy Security Act of 2009, H.R. 2454, 111th Cong. § 702 (2009).
[190] *See* U.S. EIA, *EIA projects total U.S. energy-related CO2 emissions to be relatively flat through 2050* (Feb. 10, 2020) https://www.eia.gov/todayinenergy/detail.php?id=42775.
[191] STOP B2H's Final Comments at 21.

anticipated renewable resource additions, an average intensity reduction goal to be achieved over several years is appropriate.[192]

Finally, it is worth noting that the Company has consistently demonstrated its commitment to reduce GHG emissions—its voluntary emissions reduction target has been extended and increased **twice** since its inception in 2009. And, in March 2019, Idaho Power publicly set forth a goal to providing its customers with 100 percent clean energy by 2045.[193]

2. Idaho Power Appropriately Operates Its Thermal Fleet and Participates in the EIM.

Next, STOP B2H claims that Idaho Power has "quietly embarked on a high-carbon operating strategy for its gas-fired resources," and that "unfettered trading" in the EIM appears to be the motive.[194] Specifically, STOP B2H asserts that the 2018 and 2019 operations of Langley Gulch profoundly changed, resulting in "gross inefficiencies" and an increase in the carbon intensity of the plant.[195] STOP B2H claims that the Company has operated Langley Gulch in this way to maximize EIM participation, under the false belief that EIM benefits accrue to stockholders while excess fuel costs are paid by ratepayers.[196] Based on these arguments, STOP B2H urges the Commission to investigate utility abuses in the EIM. [197] STOP B2H's conclusions and recommendations are not supported by the facts.

a. Idaho Power Efficiently Operates Langley Gulch and the Company's Broader Thermal Fleet to Serve Customers while Decreasing Overall Carbon Intensity.

STOP B2H presents the emissions intensity of Langley Gulch from 2013 to 2019, calculated with data contained in Idaho Power's FERC Form 1 report, to support its claims that "Idaho Power is quietly embarking on a high-carbon operating strategy," and that

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[192] IDACORP 2009 Annual Report at 54.
[193] Idaho Power, "Clean Today. Cleaner Tomorrow.®", available at: https://www.idahopower.com/energy-environment/energy/clean-today-cleaner-tomorrow/.
[194] STOP B2H's Final Comments at 22.
[195] STOP B2H's Final Comments at 23.
[196] STOP B2H's Final Comments at 23.
[197] STOP B2H's Final Comments at 24.

operations of Langley Gulch in 2018 and 2019 resulted in "gross inefficiencies" and an increase in carbon intensity of the plant. Upon further review of STOP B2H's calculations,[198] the Company discovered differences between the 2018 and 2019 FERC Form 1 data and actual data collected through the Company's continuous emissions monitoring system ("CEMS") and detailed gas billing records.[199]

When reporting actual emissions to various state and federal agencies, Idaho Power uses data from the CEMS, not calculations performed on FERC Form 1 data. In review of the FERC Form 1 data points for Langley Gulch in 2018 and 2019, the Company identified an error in the Quantity (Units) of Fuel Burned,[200] a value used in STOP B2H's analysis. The values for Langley Gulch in 2018 and 2019 were inadvertently overstated because of manual-entry error for the two months of August 2018 and July 2019 in the FERC Form 1.

Idaho Power appreciates STOP B2H's careful attention to Langley, which allowed Idaho Power to discover this unintentional reporting error. As a result of this error, the Company filed corrected FERC Form 1 pages on January 29, 2021. However, this minor manual-entry discrepancy is a far cry from validating STOP B2H's faulty claim that Idaho Power has embarked on a "high-carbon operating strategy."[201] There simply is no data or evidence to support such a claim.

Table 8, below, shows reported emissions for Langley Gulch for 2013 to 2019[202] and the carbon intensity measured in lbs/MWh. As can be seen from the data, the plant's emissions in 2018 and 2019 are, more or less, in line with the 2013 to 2017 timeframe, with

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[198] The Company validated that STOP B2H's calculations were performed correctly.
[199] The Company was able to validate that the emissions intensity calculated for the years 2013-2017 using FERC Form 1 data was reasonable and verified the CEMS values for 2018 and 2019 match the independent detailed billing records within 1 percent.
[200] Line 38 of page 402.1 of Idaho Power's FERC Form 1.
[201] STOP B2H's Final Comments at 22.
[202] Emissions data are publicly available on the EPA FLIGHT website at https://ghgdata.epa.gov/ghgp/main.do.

variation from year-to-year driven by underlying factors such as customer demand and weather.

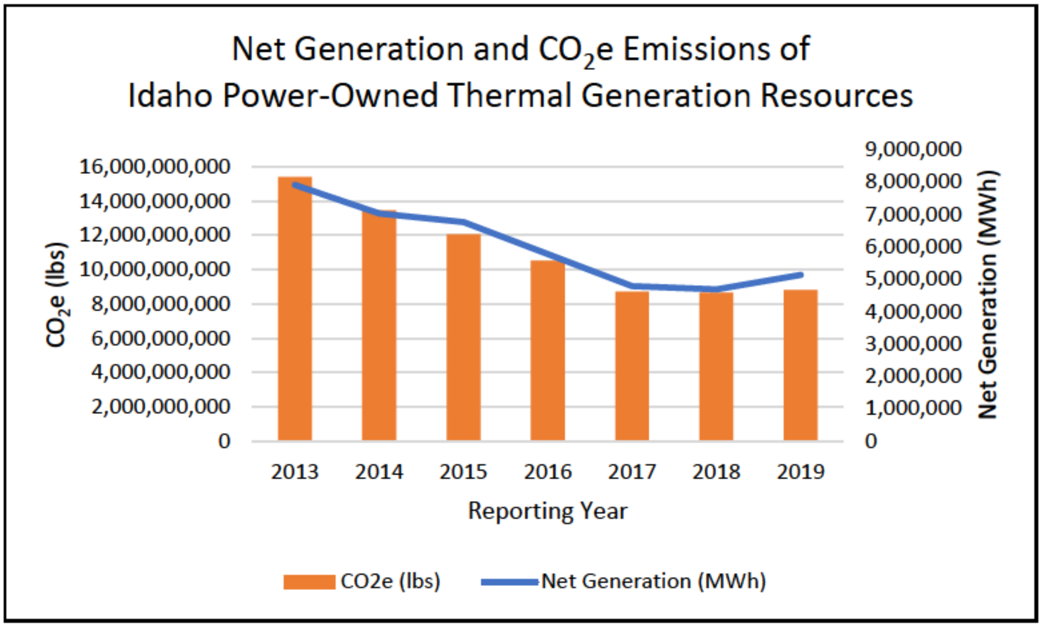
Table 8: Langley Gulch Emissions 2013–2019

Langley Gulch	2013	2014	2015	2016	2017	2018	2019
Net Generation (MWh)	1,295,859	1,049,182	1,662,770	1,420,178	1,350,692	1,131,020	1,501,436
CO2e (metric tons)[203]	483,257	389,632	619,276	537,861	505,743	423,711	563,878
CO2e (lbs)	1,065,398,047	858,990,500	1,365,268,255	1,185,779,118	1,114,971,133	934,121,745	1,243,136,716
Carbon Intensity (lb/MWh)	822	819	821	835	825	826	828

Moreover, the Company believes a better reflection of its operating strategy around carbon emissions would be to examine all Idaho Power-owned thermal generation over this same timeframe (2013-2019). From 2013 to 2019, generation from thermal resources has declined and total CO_2 emissions from those resources decreased by almost 50 percent, as shown in Figure 6 below. This data clearly demonstrates that the Company is not operating its thermal resources irresponsibly, contrary to STOP B2H's claims.

[203] EPA, Langley Gulch Power Plant, https://ghgdata.epa.gov/ghgp/service/facilityDetail/2019?id=1007379&ds=E&et=&popup=true.

Figure 6: Emission Intensity of Idaho Power's Thermal Generation 2013-2019 (Jim Bridger, Valmy, Boardman, Langley Gulch, Danskin, and Bennett Mountain power plants)



b. Idaho Power's EIM Participation Benefits Customers.

STOP B2H claims that Idaho Power's dispatch of Langley Gulch has allowed the Company's shareholders to accrue EIM benefits, while excess fuel costs are paid by customers.[204] While Idaho Power acknowledges that participation in the EIM has an impact on the dispatch of Langley Gulch, STOP B2H is incorrect that the benefits of EIM participation accrue to shareholders instead of customers. The quantification of total estimated EIM benefits is the cost savings of the EIM dispatch compared to the counterfactual without EIM dispatch. Contrary to STOP B2H's claim, benefits of participation in the EIM are not retained by shareholders.[205] Rather, both the costs and benefits flow back to customers and are realized as reduced net power supply expenses ("NPSE") reviewed by the Commission annually in the Company's power cost filings.

[204] STOP B2H's Final Comments at 23.
[205] STOP B2H's Final Comments at 23.

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To better understand how the EIM has impacted Langley Gulch dispatch, it is helpful to understand generally how the EIM works. The following is a basic summary of the way in which resources are scheduled into the EIM. First, Idaho Power creates a load forecast for the next clock hour. Second, the Company creates a generation plan to serve the forecasted load. Third, the costs for all Idaho Power generation resources are calculated. Fourth, these plans are submitted to the EIM for review and are required to pass all necessary checks. Finally, the EIM reviews all plans submitted by all participants and adjusts the dispatches of participating generation resources to minimize the total generation cost needed to serve the actual load of the participants.

Langley Gulch is a participating EIM resource and can be moved up or moved down from the planned dispatch by the EIM. Langley may be instructed to move ***down*** from planned dispatch by the EIM under the following conditions: (1) the EIM found generation available at another participating resource that was less expensive; (2) the Company's actual load was lower than projected; (3) Idaho Power's other resources (i.e., wind and solar) generated more power than was projected; or (4) any combination of the above. If Langley is instructed to move ***up*** for planned dispatch, then (1) the EIM has found a participant that could utilize the remaining generation capacity; (2) the Company's actual load was higher than expected; (3) Idaho Power's other generation (wind, hydro) was lower than expected; or (4) any combination of the above. The EIM makes economic dispatch decisions for each of the market's participants and will not instruct resources to move unless it will result in cost savings. After the fact, each market participant pays other market participants for the power it received as a result of the EIM's dispatch instructions and subsequent changes.

Thus, while operation of Langley Gulch has changed over time as Idaho Power continues its path away from baseload coal-fired generation and through participation in the

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EIM, the Company has continued to responsibly and efficiently operate its system in the best interest of its customers.

For the reasons stated above, STOP B2H's claim that the Commission should investigate abuses in the EIM is unfounded. The Company's NPSE are reviewed in detail annually by both the Idaho and Oregon commissions.

B. Gateway West

In its final comments, Staff reiterates its concern regarding the lack of consideration for the Gateway West project in the Company's IRP, relative to the efforts devoted to B2H. Staff recommends that the Company apply more resources to examine the value of this project in the 2021 IRP.[206]

Idaho Power agrees that both projects are important. Gateway West will provide significant long-term benefits, such as relieving transmission constraints, providing greater options for future generation resources, and helping to meet future transmission needs. Gateway West, however, will not provide direct access to a liquid market like B2H. As a result, Gateway West is not, as of yet, a viable replacement for Idaho Power's supply-side resources. As such, the Company believes that its analysis of Gateway West in this proceeding was appropriate given the attributes of the resource.

IX. REQUEST FOR WAIVER

As the collective review of the *Second Amended 2019 IRP* comes to conclusion, Idaho Power reiterates its appreciation of the Commission's and parties' patience in this docket. Although this extended process has taken more time and resources than anticipated, Idaho Power is confident that this investment has resulted in an accurate and more technically sophisticated resource plan.

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[206] Staff's Final Comments at 38.

Even as it seeks the Commission's acknowledgment of its *Second Amended 2019 IRP*, the Company has begun meeting with resource planning stakeholders to develop its 2021 IRP and intends to file it with the Commission by year end. To allow the Company to maintain the timing of a biennial resource plan, Idaho Power requests a waiver from IRP Guideline 3(f)'s annual update requirement:

> Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.[207]

Idaho Power requests the Commission waive the annual update requirement because the Company anticipates filing the 2021 IRP before the annual update deadline, which will be one year after the *Second Amended 2019 IRP* acknowledgment. The Commission has previously granted waivers of Guideline 3(f) where the deadline for filing an update would occur just before the next IRP would be filed.[208]

In advance of the 2021 IRP, the Company is conducting an economic and reliability analysis to determine the optimal exit date from Valmy Unit 2. This study will be complete in the first half of 2021. Given the imminence of this potential exit, Idaho Power also asks to provide the results of such analyses and, if warranted, any associated rate-making recommendations to the Commission in a separate stand-alone docket prior to filing the 2021 IRP later this year.

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[207] Order No. 07-002, Appendix A at 3.
[208] Order No. 18-176 at 14-15; Order No. 14-253 at 17-18.

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X. CONCLUSION

Idaho Power appreciates the opportunity to file these comments and supports the robust public process and participation in this case.

Respectfully submitted this 5th day of February 2021.

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