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May 15, 2020

VIA ELECTRONIC FILING AND EMAIL

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

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

Attached for filing in the above-captioned docket are Idaho Power Company's Reply Comments. Per Order No. 20-088, confidential copies are being sent via encrypted electronic ZIP file to the filing center and parties who have signed Protective Order No. 20-068.

Please contact this office with any questions.

Thank you,

Alisha Till

Alisha Till
Paralegal

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

In the Matter of: IDAHO POWER COMPANY'S 2019 Integrated Resource Plan.	**IDAHO POWER COMPANY'S** **REPLY COMMENTS**

May 15, 2020

TABLE OF CONTENTS

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Reply Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the opening comments of Commission Staff ("Staff"), the Oregon Citizens' Utility Board ("CUB"), STOP B2H Coalition ("STOP B2H"), Sierra Club, Renewable Northwest, the Renewable Energy Coalition ("REC"), and Gail Carbiener.

Idaho Power requests that the Commission acknowledge the Company's Amended 2019 Integrated Resource Plan ("IRP"), as submitted to the Commission on January 31, 2020. The IRP satisfies each of the Commission's procedural and substantive requirements. The Company's short-term action plan and preferred long-term resource portfolio are supported by robust and comprehensive analysis demonstrating the reasonableness of the plan.[1]

Idaho Power's short-term (2019-2026) action plan includes three core resource actions: (1) adding 120 MW of solar photovoltaic ("PV") capacity in 2022; (2) exiting from three coal-fired generating units by year-end 2022 (including Valmy 1 at year-end 2019), and from five total coal-generating units by year-end 2026; and (3) bringing the Boardman-to-Hemingway ("B2H") transmission project on-line in 2026. These three sets of resource decisions are largely supported by the parties to this proceeding, with the exception of STOP B2H's and Mr. Carbiener's opposition to the B2H transmission line. Nonetheless, parties present a range of suggestions and feedback on the Company's portfolio design and analysis, reliance on market purchases, treatment of certain supply-side and demand-side resources, and development of long-term forecasts. Parties' comments on each of these categories are addressed in turn.

[1] *Re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007).

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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.[2] The primary goal of an IRP is to select the least cost and least risk portfolio for the utility and customers.[3] To meet this goal, the Commission requires the IRP to analyze a planning horizon of "at least 20 years."[4] While the fundamental goal of the IRP is the identification of a preferred portfolio, the Commission's guidelines also require the Company to include an action plan that identifies the specific resource activities the utility intends to undertake in the next two to four years.[5] When adopting the IRP guidelines, the Commission noted that, "in an IRP, the Commission looks at the reasonableness of individual action items in the context of the entire plan."[6]

When acknowledging an IRP, the Commission acknowledges only the action plan and prefers to focus on action items planned to occur in the next four years.[7] 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

[2] *In the Matter of Idaho Power Company, 2013 Integrated Resource Plan*, Docket LC 58, Order No. 14-253 at 1 (July 8, 2014).
[3] 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.").
[4] Order No. 07-002 at 5.
[5] Order No. 07-002 at 12 (Guideline 4(n)).
[6] Order No. 07-002 at 25.
[7] Order No. 14-253 at 12; *In the Matter of Idaho Power Company, 2011 Integrated Resource Plan*, Docket 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 . . .").

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available at that time.[8]

Importantly, the Commission has repeatedly "reaffirm[ed] [its] long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding."[9]

III. BOARDMAN TO HEMINGWAY

As explained in more detail below, the B2H transmission line continues to be a top performing resource alternative, providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market. Originally specified as a 285 MW transmission capacity resource in the Company's 2006 IRP preferred portfolio, expanding Idaho Power's connection to the Pacific Northwest power markets, the B2H project has served as a critical component of Idaho Power's preferred portfolios since the 2009 IRP and has consistently been analyzed and proven to be the least-cost, least-risk resource for customers. In the last five IRPs, the Commission has recognized that continued development of the project is reasonable.

The 2017 IRP represented a key milestone in the Company's ongoing efforts to develop the B2H line, as the Company relied on the Commission's acknowledgement of preliminary construction activities in support of its application for a site certificate before Oregon's Energy Facility Siting Council ("EFSC"). As on-going evidentiary support for that proceeding, the Company again requests acknowledgment of the action plan in the Amended 2019 IRP, and specifically the decision to continue permitting activities and to continue preliminary construction activities for the B2H transmission line. Thus, acknowledgment of this

[8] Order No. 14-253 at 1; *but see In the Matter of Idaho Power Company, 2017 Integrated Resource Plan*, Docket LC 68, Order No. 18-176 at 6 (May 23, 2018) (recognizing that the B2H short-term action plan was from 2017 to 2026).
[9] Order No. 14-253 at 1.

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IRP is critical to allow project development to continue moving forward so that the transmission line can be placed in service by 2026 to meet the needs of Idaho Power's customers.

A. B2H is Essential to Meet Clean Energy Goals.

Energy companies are increasingly transitioning to clean energy to meet the ambitious clean energy goals adopted both by states and utilities. As described in more detail below, Idaho Power has set a goal of 100 percent clean energy by 2045. Meeting these goals will require large amounts of clean energy, which in turn will require significant available transmission to effectively integrate variable and intermittent renewable output. Transmission also helps ensure that, throughout this transition, service remains reliable and affordable. While alternatives to significant transmission development, such as local distributed energy resources, will also play a role in the future grid, the scale of the Company's ambitious renewable energy goals will require new and robust transmission infrastructure to ensure both reliable integration of utility-scale renewable resources, as well as access to energy markets.

The B2H transmission line is critical to Idaho Power's clean energy goal, allowing the Company to continue its glide path away from coal and towards 100 percent clean energy by 2045. Indeed, a key component of the Company's short-term action plan—the Company's early exit from a second Bridger unit in 2026—is tied to the need for an additional resource, and B2H is the least-cost, least-risk replacement resource to ensure ongoing system reliability. Moving forward, Idaho Power is confident that B2H will play an important role in allowing the Company to meet its clean energy goals while ensuring least-cost, least-risk service for customers.

B. Idaho Power's B2H Co-Participants Have Demonstrated Ongoing Commitment to the Project.

In opening comments, Staff,[10] STOP B2H,[11] Mr. Carbiener,[12] and CUB[13] express concern regarding the possibility of future ownership changes for B2H, and how such changes might impact the project's costs, the Company's preferred portfolio, and the Company's short-term action plan.

First, both PacifiCorp and the Bonneville Power Administration ("BPA") have demonstrated ongoing financial commitment to the B2H project. To date, the three parties have contributed a total of $108 million to support permitting and certain preliminary construction activities for B2H pursuant to the Joint Permit Funding Agreement. In addition, the project co-participants recently executed Amendment No. 2 to the Joint Permit Funding Agreement, which moves certain preliminary construction activities into the existing Joint Permit Funding Agreement. Idaho Power will provide updates to the Commission when any applicable new agreements are finalized. Idaho Power believes that the amended Permitting Agreement, the B2H co-participants' ongoing financial commitments, and the Company's capital-cost assessment,[14] demonstrate PacifiCorp's and BPA's commitment to the ongoing development of B2H as a cost-effective resource for customers.

Second, changes in ownership shares of B2H are hypothetical at this point. The Company and its B2H co-participants are discussing the optimal way to meet customers' needs. Discussions are broader than just B2H capacity and include other factors, such as asset exchanges, to facilitate optimal benefits. These discussions are fluid, and Idaho Power will provide updates to the Commission when any applicable new agreements are finalized.

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[10] Staff's Opening Comments at 23 (Apr. 1, 2020).
[11] STOP B2H's Amended Opening Comments at 57.
[12] Gail Carbiener's Opening Comments at 2 (Apr. 2, 2020).
[13] CUB's Opening Comments at 9-10 (Apr. 2, 2020).
[14] Idaho Power's Amended 2019 IRP, App. D at 53 (Jan. 31, 2020).

Idaho Power will model any changes in B2H ownership interest or other broader arrangements, if applicable, in the 2021 IRP. The Company and its co-participants also continue to have discussions with other electric power providers in the region to determine if there is interest in additional participation in ownership beyond the initial three parties. Any additional participation could result in a change to the overall ownership of the project. Thus, while the three initial co-participants have discussed possible changes in ownership based on each party's customer needs, these discussions have not matured.

Beyond mere shifts in ownership share, CUB inquires if either B2H's online date or the Company's planned exit from the second Jim Bridger unit would change if one or more of the Company's co-participants decided to wholly abandon the project.[15] Idaho Power does not presently have enough information to determine how the B2H in-service date would be impacted if one or more of the project's co-participants withdrew entirely. More importantly, the Company does not believe that such abandonment is a sufficiently significant risk to require modeling in the Company's IRP. As explained above, both of the Company's B2H co-participants have demonstrated ongoing financial commitment to developing B2H.

Perplexingly, STOP B2H describes the co-participants' agreed-upon extension to execute the Development and Construction Agreement as "problematic" because EFSC may issue its Proposed Order—thereby allowing actual construction to begin—before the extension expires on July 15, 2020.[16] STOP B2H's concern is misplaced. First, the Proposed Order does not provide Idaho Power with permission to begin construction or any other activity. Any construction activity for which permission is required—*i.e.*, most groundbreaking activities—may not proceed until after Idaho Power receives a site certificate from EFSC,

[15] CUB's Opening Comments at 9-10.
[16] STOP B2H's Amended Opening Comments at 57.

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which is expected to occur in 2021.[17] Moreover, the extension of the date to execute the Development and Construction Agreement in no way impedes Idaho Power's ability to continue with the permitting and pre-construction activities in which it is currently engaged.

Finally, STOP B2H also argues that PacifiCorp is not sufficiently committed to the project because B2H was not included in that company's 2019 IRP as part of the short-term action plan. Idaho Power cannot speak to another company's IRP process. More importantly, PacifiCorp and BPA have both continued to fund ongoing project activities and to support the project's development.

C. B2H's Costs are Not Understated.

STOP B2H claims that Idaho Power understates the cost of B2H as compared to the 2017 IRP and asks the Commission to compel Idaho Power to explain why B2H's net present value ("NPV") "has fallen from $384 million in the 2017 IRP to $111 million in the 2019 IRP."[18] STOP B2H's argument confuses several NPV amounts. For instance, the NPV in the 2017 IRP was based on a 55-year forecast. STOP B2H tries to compare this 2017 figure to the 2019 NPV that describes costs through the 20-year IRP planning window. The nominal costs captured in STOP B2H's table (labeled "Figure 1") are accurate and represent Idaho Power's 21.2 percent share of the estimated direct expenses, plus its entire AFUDC cost.[19]

D. B2H is Appropriately Evaluated as a Supply-Side Resource in the IRP but is Exempt from Oregon's Competitive Bidding Rules.

STOP B2H questions whether B2H is appropriately evaluated as a supply-side resource, and then argues that, to the extent that B2H ***is*** appropriately evaluated as a supply-side (or capacity) resource, the Commission should require Idaho Power to apply the

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[17] Certain surveying activities may be conducted prior to the issuance of a site certificate. However, the Proposed Order does not provide authorization for that applicant to engage in this or any other activity.
[18] STOP B2H's Amended Opening Comments at 6.
[19] STOP B2H's Amended Opening Comments at 6 (Figure 1).

Commission's competitive bidding rules[20] to B2H—notwithstanding the explicit exemption in those rules for transmission projects. Specifically, STOP B2H argues that the Commission may not acknowledge B2H in the IRP until Idaho Power formally requests a waiver of the competitive bidding rules. STOP B2H also requests that the Commission further explain its prior decision acknowledging B2H on the basis that doing so "effected a waiver of B2H from Oregon's competitive bidding rules."[21] As set forth below, B2H is appropriately considered as a supply-side resource and, because transmission (even when analyzed as a capacity resource) is exempt from the competitive bidding rules, there is no reason for Idaho Power to request a waiver of those rules.

1. <u>B2H is Appropriately Considered a Supply-Side Resource.</u>

STOP B2H asserts that "modeling B2H as a supply side resource in an IRP violates best practices and is contrary to the best interests of Oregon and Oregon ratepayers," but also notes that it does not wish to "revisit" the issue of the treatment of B2H as a supply-side resource in the IRP.[22] While it appears that STOP B2H may not wish to engage in further discussion on this point, we nonetheless respond to address STOP B2H's apparent confusion regarding the Commission's IRP guidelines.

The IRP guidelines provide that "utilities should consider . . . electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability."[23] Consistent with this direction, Idaho Power has appropriately accounted for the costs of the underlying market transactions when determining the forecasted overall costs and benefits associated with the B2H line. Idaho Power also

[20] OAR Chapter 860, Division 089.
[21] STOP B2H's Amended Opening Comments at 4-5.
[22] STOP B2H's Amended Opening Comments at 3-4.
[23] Order No. 07-002 at 13.

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Portland, Oregon 97205

notes that the Company's approach in this IRP is consistent with its historical treatment of B2H in prior IRPs, which have analyzed B2H as a supply-side resource because it allows greater access to Northwest markets, thereby allowing Idaho Power to import additional lower-cost energy to serve its Oregon and Idaho customers.

STOP B2H also argues that it is problematic that "Idaho Power has not identified any quantifiable supply side generating resources that would be transmitted by the power line" and instead will rely on "spot market energy trading."[24] However, STOP B2H's criticism overlooks that the B2H transmission line is being proposed to provide Idaho Power with better access to the Pacific Northwest power markets, and specifically to the Mid-Columbia ("Mid-C") market, which is the most liquid market hub in the region.[25] Given that Idaho Power is proposing to access a ***market*** (and not any one particular generating resource), there is no reason for Idaho Power to identify specific generating resources in connection with B2H.

STOP B2H further argues that reliance on market trading is not a responsible long-term power supply strategy.[26] This claim is wholly without merit and, to the contrary, the Company (and its customers) already benefit from the Company's strategic use of power market purchases to meet its peak demand. Specifically, Idaho Power's reliance on regional power markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources—revenues which are flowed through as an offset to net power supply costs through the Company's power cost adjustment.[27] Additionally, in Appendix D of its Amended 2019 IRP, Idaho Power analyzed this strategy in connection with B2H and concluded that developing B2H will allow Idaho Power to use the

[24] STOP B2H's Amended Opening Comments at 3.
[25] Idaho Power's Amended 2019 IRP, App. D at 9.
[26] STOP B2H's Amended Opening Comments at 3.
[27] Idaho Power's Amended 2019 IRP at 40.

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Portland, Oregon 97205

Mid-C market more to economically serve Idaho Power's customers. STOP B2H's concern regarding the Company's reliance on energy markets is misplaced and should be disregarded.

2. <u>The Commission Recently—and Deliberately—Made a Policy Determination to Exempt Transmission from the Competitive Bidding Rules.</u>

STOP B2H acknowledges the provision *specifically exempting* transmission from application of the competitive bidding rules,[28] but nonetheless argues that the exemption should not apply because B2H is being treated as a capacity resource in the IRP.[29] This reasoning is incorrect, however, because the record in Docket AR 600 demonstrates that the Commission determined the rule exempting transmission was needed *precisely* to clarify the otherwise ambiguous rule language that may suggest that transmission assets, acquired as capacity resources, would be subject to the competitive bidding rules. While we believe that the rule language[30] and the Commission's policy direction[31] is clear and speaks for itself, we nonetheless briefly summarize the Commission's prior consideration of this issue in Docket AR 600.

Historically, competitive bidding applied only to generating resources. However, in Docket AR 600, Staff proposed that the new competitive bidding rules apply to "energy or capacity resources"—language which, without clarification, was ambiguous and may have been broad enough to include transmission resources. In light of that ambiguity, the Commission invited stakeholders to weigh in about whether the acquisition of transmission facilities should be subject to the competitive bidding rules.[32] Idaho Power, along with other stakeholders, advocated that the Commission should not subject transmission to the competitive bidding rules, and provided detailed comments explaining that competitive bidding

[28] STOP B2H's Amended Opening Comments at 4.
[29] STOP B2H's Amended Opening Comments at 5.
[30] OAR 860-089-0100(3)(d).
[31] In the Matter of Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, Docket AR 600, Order No. 18-087 (Mar. 19, 2018).
[32] Docket AR 600, Notice at 1-2 (Jan. 25, 2018).

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Portland, Oregon 97205

is neither practical for transmission nor expected to yield any benefits for ratepayers.[33] After weighing the parties' positions, the Commission provided explicit policy direction to Staff that it should revise the rules to provide "clarification that the rules are not intended to require competitive bidding of transmission projects."[34] Given the Commission's conclusive statement, STOP B2H's proposal to ignore the exemption for transmission must be rejected.

Finally, because the competitive bidding rules do not apply in the first instance, there is no need for a waiver from those rules for B2H.

E. Emergency Transmission Capacity Does Not Offset the Need for B2H.

STOP B2H argues that the Company's Capacity Benefit Margin ("CBM") can and should be used as a resource to offset the need for B2H.[35] STOP B2H suggests that unspecified other resources could instead be used to support system reliability, freeing dedicated CBM transmission capacity and avoiding the need for additional transmission.[36]

By way of background, CBM is transmission capacity set aside for system emergencies, thereby allowing transmission customers to reduce the amount of internal generation they must supply to maintain an adequate planning margin. Given that this transmission must be available in emergencies, transmission capacity allocated to CBM is unavailable for firm use.[37]

Here, Idaho Power has 330 MW of transmission capacity dedicated to CBM. However,

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[33] Docket AR 600, Joint Utilities' Opening Comments on Policy Issues (Feb. 14, 2018) (explaining that transmission should be exempt from the Competitive Bidding Rules because: (1) the Commission has never subjected transmission to competitive bidding, and doing so would represent a major policy shift that had not been recommended or justified by any party; (2) there is no competitive market for transmission in Oregon, and thus even if competitive bidding were required, it would not likely result in any participation from developers given the lengthy and costly permitting processes; (3) if or when a competitive market is established, it would likely occur through the formation of a Regional Transmission Operator (RTO) or Independent System Operator (ISO), but neither exist in the Pacific Northwest at this time; and (4) subjecting transmission to competitive bidding would potentially extend an already lengthy permitting process).
[34] Docket AR 600, Order No. 18-087 (Mar. 19, 2018).
[35] STOP B2H's Amended Opening Comments at 19.
[36] STOP B2H's Amended Opening Comments at 20
[37] Idaho Power's Amended 2019 IRP, App. D at 14.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

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. Indeed, STOP B2H overlooks the fact that, by serving as an emergency resource in Idaho Power's Planning Margin, the 330 MW of CBM is *already included* as a resource in the IRP. Thus, reducing or eliminating CBM simply moves the need for capacity from one bucket (serving load) to another bucket (Planning Margin), while having zero impact on the Company's overall system need.[38]

Moreover, STOP B2H is incorrect that the financial impact of maintaining CBM capacity as an emergency resource costs customers $9 million each year.[39] To reach this figure, STOP B2H incorrectly assumes that Idaho Power pays the full point-to-point transmission rate to reserve the necessary transmission capacity. This is simply not true. Idaho Power's transmission costs are included in the development of the revenue requirement for the Company's retail customers, with revenues received from transmission customers offsetting those costs.[40] Although the network transmission revenue requirement computed as part of Idaho Power's transmission formula rate includes an addition associated with CBM, and Idaho Power's network customers pay their load ratio share of this revenue requirement, there is *no additional cost* to the Company's retail customers.

F. Idaho Power Has Accounted for the Impact of B2H and Associated Market Purchases on Line Losses.

STOP B2H claims that Idaho Power has failed to account for the fact that buying power

[38] STOP B2H advances a number of related points premised on the idea that eliminating CBM will increase the capacity Idaho Power has available to meet minimum resource margins. Given that CBM is already included in Idaho Power's Planning Margin, these arguments are based on the same flawed premise. STOP B2H's Amended Opening Comments at 21-23.
[39] STOP B2H's Amended Opening Comments at 21.
[40] *In the Matter of Idaho Power Co., Request for a Gen. Rate Revision*, Docket UE 233, Order No. 12-055, App. A at 16 (Feb. 23, 2012) (showing transmission costs in the Company's revenue requirement calculation).

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Portland, Oregon 97205

from distant markets will cause an increase in transmission line losses, and urges the Company to instead explore "locating resources closer to load."[41] However, contrary to STOP B2H's claim, B2H will actually *reduce* line losses in the western system.

Line losses occur on all transmission lines, as energy encounters resistance over distance traveled. However, transmission efficiency is significantly improved, and line losses decreased, on large, low-resistance, high-voltage lines like B2H. Indeed, if B2H were simply added to the western system, while maintaining the same grid dispatch patterns as are present today, the new line would reduce the system's line losses drastically.

It is true that B2H will allow for additional capacity purchases, and thus result in increased current flow with associated line losses. However, as discussed below, such increased transfers will not overcome the reduction in line losses attributable to B2H.

To ascertain B2H's total contribution to reducing line losses, Idaho Power analyzed three 2030 base cases created by the Western Electricity Coordinating Council ("WECC"),[42] without modification, and compared losses with and without the B2H project being placed in service. This analysis demonstrates that B2H provides over 100 MW of line loss reductions in the peak summer case, and a minimum of 15 MW of line loss reductions in the light load spring case, as shown below:

Table 1: B2H Loss Reductions

	Peak Summer WECC Power Flow Case	Peak Winter WECC Power Flow Case	Light Spring WECC Power Flow Case
B2H Loss Reductions	117 MW	68 MW	16 MW

[41] STOP B2H's Amended Opening Comments at 17-18.
[42] WECC, "Base Cases" (accessed May 3, 2020) *available at*: https://www.wecc.org/SystemStabilityPlanning/Pages/BaseCases.aspx ("WECC's base cases are computer models of projected or starting power system conditions for a specific point in time. These base cases include both steady state and dynamic data, and contain very large amounts of data necessary to model power system behavior.").

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Portland, Oregon 97205

STOP B2H attempts to illustrate the substantial line losses associated with B2H-enabled market purchases by describing what would happen if Idaho Power ceased operating Langley Gulch (a natural gas combined cycle power plant located adjacent to Idaho Power's Treasure Valley load center) and instead scheduled replacement power from the Mid-C.[43] Under this improbable scenario, line losses could increase by as much as 15 percent.[44] While such a result is theoretically possible (depending on the physical stress of the transmission system at any given time), STOP B2H's hypothetical scenario misunderstands the role of market purchases. Idaho Power is not pursuing market purchases to *replace* (*i.e.*, shut off) local gas-fired resources. Instead, the Company is (1) avoiding building a new gas fired resource (local or remote), and (2) retiring additional coal resources that are similarly remote. Indeed, Idaho Power will exit a coal-fired resource—Jim Bridger—located over 400 miles to the east, and will replace that energy with a Mid-C resource about 400 miles to the west. Both resources have inherent line losses. Thus, STOP B2H's hypothetical scenario is as unhelpful as it is unlikely.

In addition to claiming that Idaho Power does not adequately account for line losses in its planning process, STOP B2H asserts that Idaho Power's trading operators do not "consider these incremental [line] losses when making decisions [about] whether to generate power within the Idaho System, or to instead buy distant power[.]"[45] Once again, this assertion is simply untrue. As a transmission system operator, Idaho Power seeks opportunities to maximize efficiencies because such optimization achieves lower costs for Idaho Power's customers. Indeed, Idaho Power has infrastructure in place to meet the peak need so that, during abnormal conditions, the system can meet even emergency-level need. There is no basis for STOP B2H's assertion that the Company fails to account for the impact of line losses

[43] STOP B2H's Amended Opening Comments at 16.
[44] STOP B2H's Amended Opening Comments at 16.
[45] STOP B2H's Amended Opening Comments at 17.

on the economics of operating decisions.

Lastly, pointing to a recent Idaho Power filing with the Federal Energy Regulatory Commission ("FERC"), STOP B2H contends that Idaho Power's line losses have "sharply increas[ed]" since joining the EIM, and claims that this increase foreshadows a similar increase associated with B2H-enabled market purchases.[46] However, Idaho Power's line losses have in fact *decreased* since joining the EIM, as shown in Table 2, below.

Table 2: Idaho Power's Reported Losses

Source	Total Losses (MWh)	% of Total Energy
2017 Losses, FERC Form 1 pg 401a Line 27	1,267,436	6.99%
2018 Losses, FERC Form 1 pg 401a Line 27	1,256,411	6.77%
2019 Losses, FERC Form 1 pg 401a Line 27	1,146,823	6.19%

Moreover, the FERC filing referenced by STOP B2H concerned an accounting and settlements issue regarding how line losses were being allocated to different Idaho Power customers in the Western EIM.[47] The Company's FERC comments are irrelevant to the simple and verifiable fact that, far from sharply increasing line losses, Idaho Power's losses have actually declined since joining the EIM.

G. EFSC's Rules Governing Issuance of a Site Certificate are Inapplicable to this IRP Proceeding.

STOP B2H presents detailed comments asserting that Idaho Power has not satisfied EFSC's Need Standard for purposes of issuing a site certificate for B2H. In fact, these are the same comments that STOP B2H previously submitted in response to the EFSC Draft Proposed Order ("DPO") for B2H, with minor modifications to update certain tables.[48] STOP

[46] STOP B2H's Amended Opening Comments at 17-18.
[47] FERC Docket No. ER20-1370-000, "Changes to Open Access Transmission Tariff Modification, Attachment O – Energy Imbalance Market," Idaho Power Company's Proposed Revised Open Access Transmission Tariff (Mar. 23, 2020), *available at* https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14844783.
[48] STOP B2H's Amended Opening Comments at 24 ("The STOP B2H Coalition submitted detailed comments on these rules to the Energy Facilities Siting Council (EFSC). These are shown below, with updated tables from Idaho Power['].s 2019 IRP highlighted in red.").

B2H claims, once again, that Idaho Power cannot meet either of the two bases for satisfying EFSC's Need Standard: (1) conformity with EFSC's least-cost plan rule (OAR 345-023-0020(1)),[49] or (2) meeting the system reliability rule (OAR 345-023-0030), because the Commission has purportedly acknowledged only Idaho Power's portion of B2H, rather than the full 500-kV line.[50] STOP B2H also requests that the Commission rescind the portion of its Order No. 18-176 acknowledging Action Item 6 (including preliminary construction activities, acquiring long lead time material, and constructing the B2H project), because the "[C]ommission's acknowledgment of action item 6 triggered this process at [the Oregon Department of Energy]."[51] STOP B2H's comments regarding the application of the EFSC standards to B2H are both outside the scope of this proceeding and substantively incorrect. Moreover, STOP B2H's request for partial rescission of Order No. 18-176 misunderstands the Commission's role in IRP acknowledgement and must be rejected.

1. <u>The Application of EFSC's Need Standard is Beyond the Scope of this Docket.</u>

First, STOP B2H's comments are clearly beyond the scope of this proceeding because they concern the application of the rules of another administrative agency. Thus, even were the Commission to consider STOP B2H's arguments, this Commission would not have authority to render judgment. Notably, in its acknowledgement of the 2017 IRP in Order No. 18-176, the Commission appropriately clarified the limited scope of its decision: "[O]ur acknowledgement is limited to our interpretation of IRP standards specific to the Public Utility Commission, and does not interpret or apply the standard of any other state or federal agency."[52] The Commission should reaffirm that it will not be determining whether or not Idaho Power's EFSC application—or its IRP—satisfies EFSC's legal standards.

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[49] STOP B2H's Amended Opening Comments (Revised) at 25.
[50] STOP B2H's Amended Opening Comments (Revised) at 31.
[51] STOP B2H's Amended Opening Comments (Revised) at 24.
[52] *In the Matter of Idaho Power Company, 2017 Integrated Resource Plan*, Docket LC 68, Order No. 18-176 at 1 (May 23, 2018).

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Second, as Idaho Power explained in responsive comments filed with EFSC, STOP B2H is substantively mistaken because the Commission's acknowledgment of Idaho Power's 2017 IRP constituted acknowledgment of the Company's decision to proceed with permitting and pre-construction activities for the full, 500-kV line. While, as explained above, Idaho Power understands that it is not the role of the Commission to weigh in on issues of substantive compliance with the EFSC standards, Idaho Power recognizes that the Commission and stakeholders may be interested in the interplay between the IRP and EFSC process. Accordingly, interested stakeholders may consider Idaho Power's DPO Comment Responses that were provided in response to STOP B2H's arguments about the EFSC need standards.[53]

2. <u>There is No Basis for the Commission to Rescind Order No. 18-176.</u>

On May 18, 2018, in Order No. 18-176, the Commission acknowledged two key action items pertaining to B2H: (1) Action Item 5, to conduct ongoing permitting, planning studies, and regulatory filings for the B2H transmission line, and (2) Action Item 6, to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H Project.[54] Because the Company relies on the Commission's Order No. 18-176 to demonstrate conformity with EFSC's least-cost plan rule, STOP B2H requests that the Commission rescind the portion of Order No. 18-176 acknowledging Action Item 6.[55] However, STOP B2H misunderstands the Commission's role in the IRP process, and has provided no factual or legal basis for partial rescission of Order No. 18-176.

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[53] Idaho Power's DPO Comment Responses at pages 94-100 (Nov. 7, 2019), *available at* https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2019-11-07-B2HAPP-DPO-IPC-Responses-to-Select-DPO-Comments.pdf

[54] Order No. 18-176 at 9.

[55] STOP B2H characterizes the Commission's Order No. 18-176 as "triggering" the ODOE/EFSC process. This statement is incorrect, as the issuance of the Commission's Order No. 18-176 did not "trigger" any activity at EFSC. Instead Idaho Power relies on the Order No. 18-176 as evidence in the ODOE/EFSC Application for Site Certificate process.

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In resource planning, the Commission's role in acknowledgement is to consider whether the utility's proposed actions are reasonable at the time of acknowledgment; that acknowledgement may be later used to inform ratemaking for the resource.[56] As the Commission appropriately noted in its Order No. 18-176, consideration of the application of the EFSC's standards is beyond the scope of its role in IRP acknowledgement. The Company's reliance on the IRP acknowledgement in other forums has absolutely no bearing on the on-going validity of the order or the analysis underlying the order.

Additionally, STOP B2H has not presented any evidence to suggest that the Commission's Order No. 18-176 was based on inaccurate information or otherwise inappropriately decided. Accordingly, STOP B2H's request for partial rescission of Order No. 18-176 must be rejected.

IV. PORTFOLIO DESIGN AND ANALYSIS

To briefly summarize, Idaho Power's portfolio modeling proceeded in four steps. ***First,*** the Company used the AURORA model to identify 24 portfolios optimized for the WECC region. ***Second,*** the Company evaluated the NPV for each of these 24 portfolios under both high and expected gas and carbon cost forecasts to identify the risk of significant cost variability. Based on this variability risk, the Company identified two sets of portfolios (each set including a B2H and non-B2H option, yielding four portfolios in total) for further analysis. ***Third,*** the Company analyzed the four selected portfolios using manual adjustments to determine the most cost-effective resource plan for Idaho Power under various Jim Bridger exit scenarios. ***Fourth,*** the Company performed stochastic risk analysis on both the WECC-optimized and the manually adjusted portfolios to determine each portfolio's sensitivity to load

[56] OPUC Internal Operating Guidelines at 27 *available at:* https://www.oregon.gov/puc/forms/Forms%20and%20Reports/Internal-Operating-Guidelines.pdf.

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Portland, Oregon 97205

changes, hydrologic conditions, and natural gas price shocks.[57] Parties' comments on each of these four steps are addressed in turn.

At a high level, Staff raises concerns regarding the Company's overall portfolio design and analysis process, asserting that Idaho Power failed to provide a systematic qualitative review in its analysis and to address the impact of these risks on the preferred portfolio, as the Company provided in past IRPs. Staff urges the Company to systematically assess the impact of qualitative factors in this and future IRPs.[58] However, relevant qualitative factors are described in detail in the Company's IRP, and include natural gas price volatility, variability in hydrologic conditions, and market price variability.[59] Two of these factors—natural gas price volatility and hydrologic conditions—were in fact analyzed in the Company's stochastic risk analysis. As explained in Idaho Power's IRP, the Company's quantitative analysis also yielded a reliable proxy analysis for market price variability,[60] as market prices are strongly driven by positive correlations with natural gas price and carbon cost, and by a negative correlation with hydro conditions.[61] Nonetheless, Idaho Power will look to enhance its qualitative analysis for the 2021 IRP.

A. Portfolio Modeling

Parties question several aspects of the Company's initial portfolio modeling: (1) why the Company used the Long-Term Capacity Expansion ("LTCE") tool in AURORA to optimize portfolios on a WECC-wide basis, rather than on a Company-wide basis; (2) whether the Company accounted for renewable tax credits; and (3) whether the Company made additional

[57] Idaho Power's Amended 2019 IRP at 114-115 (showing stochastic analysis results for both sets of portfolios).
[58] Staff's Opening Comments at 8.
[59] Idaho Power's Amended 2019 IRP at 117.
[60] Idaho Power's Amended 2019 IRP at 111-113.
[61] Idaho Power's Amended 2019 IRP, App. D at 53.

discretionary adjustments between B2H and non-B2H portfolios.[62] As explained in more detail below, Idaho Power appropriately used the LTCE tool in AURORA modeling, accounted for tax credits where appropriate, and applied Company-specific adjustments to ensure the least-cost, least-risk result for Idaho Power's customers.

1. <u>The Company Used the LTCE Tool Appropriately in its Portfolio Modeling.</u>

As an initial matter, Staff expresses appreciation for the Company's use of LTCE modeling and for the Company's effort to develop a wider range of portfolio options.[63] However, Staff questions how the Company applied the LTCE tool. Specifically, Staff notes that Idaho Power used the LTCE tool in AURORA to identify WECC-optimized portfolios, and then manually adjusted these portfolios to arrive at a preferred portfolio.[64] Staff describes this approach as "novel," explaining that other companies generally use the LTCE tool to develop portfolios that are optimized "based on that company's system" because the buildout that is most cost-effective for the entire WECC may not be the same as the buildout that is most cost-effective for a particular company.[65]

AURORA's LTCE analysis optimizes regional build-out portfolios on the basis of a range of inputs, including costs, constraints, and demand.[66] The Company agrees with Staff that a model that optimizes for Idaho Power's system would have been preferable. However, at the time the 2019 IRP analysis was conducted, the Company's selected software was not able to perform this type of analysis. The Company evaluates modeling software prior to each IRP analysis, conducting outreach to different software vendors to learn about model capabilities and contacting peer utilities to understand the tools employed and the strengths

[62] Staff's Opening Comments at 5 ("Staff does have concerns about the design process and transparency behind some of the manual adjustments.").
[63] Staff's Opening Comments at 5.
[64] Staff's Opening Comments at 5.
[65] Staff's Opening Comments at 5.
[66] Idaho Power's Amended 2019 IRP at 2.

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and weaknesses of each. The Company ultimately selects modeling software according to what provides the best fit for the Company's system and needs.

Here, the Company believes that its LTCE approach was appropriate. By using the LTCE analysis and then performing limited manual adjustments, the Company's approach to portfolio modeling appropriately leveraged the analytical rigor of the LTCE tool while allowing the Company to ensure that the results were optimized to yield the most cost-effective solution for Idaho Power's system. Looking forward, however, the Company has been exploring Staff's preferred approach to applying the LTCE tool and has identified improvements for the 2021 IRP.

2. <u>The Company's Analysis Accounted for Renewable Tax Credits.</u>

Staff and Renewable Northwest ask whether the IRP analysis considered the Investment Tax Credit ("ITC") and the Production Tax Credit ("PTC"), and ask the Company to explain how these factors were addressed in the capacity expansion analysis.[67] The ITC for solar was included in the AURORA LTCE simulations. The PTC for wind was evaluated during the 2019 IRP setup; however, the Company determined that, because of the impending tax credit expiration and lack of near-term resource need where the PTC might apply, the PTC for future wind would not be included for modeling purposes.

3. <u>Idaho Power Did Not Make Additional Discretionary Adjustments to the AURORA Optimization Between the B2H and Non-B2H Portfolios.</u>

STOP B2H alleges that Idaho Power made unidentified modeling adjustments in the development of WECC-optimized portfolios beyond adding B2H to Portfolio's 1 through 12 (thereby producing the results for Portfolios 13 through 24).[68] To support this theory, STOP B2H provides analysis suggesting that market purchases change in "counterintuitive" ways

[67] Staff's Opening Comments at 9-10 and Renewable Northwest's Opening Comments at 6 (Apr. 2, 2020).
[68] STOP B2H's Amended Opening Comments at 13.

between the B2H and non-B2H portfolios.[69] STOP B2H asks the Company to explain this anomaly and to identify any errors or undisclosed modeling changes associated with adding B2H import capacity into the model.[70]

After a review of STOP B2H's analysis, it appears that STOP B2H includes data from the 2019 IRP filed in June 28, 2019, which differed from the data in the Amended 2019 IRP filed on January 31, 2020. Apart from that error, STOP B2H appears to misunderstand the data used in its analysis. The AURORA setup for B2H remained the same between the original and amended IRPs. However, because Idaho Power's AURORA model used LTCE modeling parameters, each portfolio's LTCE buildout of resources was unique and resulted in varying levels of market purchases over the 20-year planning period.[71] Figure 1, below, corrects and updates STOP B2H's Figure 4, adding the Company's preferred portfolio, P16(4), for comparison.

[69] STOP B2H's Amended Opening Comments at 14.
[70] STOP B2H's Amended Opening Comments at 13-15.
[71] Idaho Power's Amended 2019 IRP at 2 (explaining the LTCE modeling review). To be clear, the market purchase data used by STOP B2H includes *all* market purchases for each portfolio by year, not just incremental market purchases as a result of adding the B2H line.

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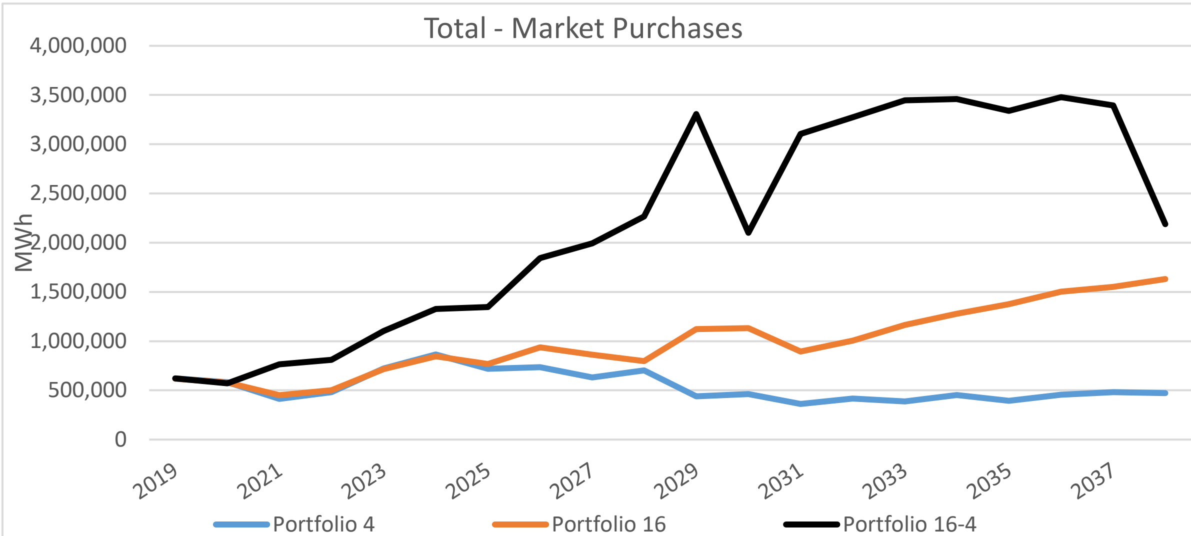
Figure 1: Corrected and Updated Figure 4 from STOP B2H Opening Comments



To be clear, *the LTCE buildout of resources is the single greatest factor in the above levels of market purchase forecasts*. To understand this relationship, it is helpful to examine more closely the new resources associated with the different portfolios. Figure 2, below, shows the resource buildouts underlying the market purchase data for Portfolios 4, 16, and 16(4). (Portfolio 16 corresponds to Portfolio 4, but with B2H added. Portfolio 16(4) is

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Portfolio 16 following the Company's manual adjustments.)

Figure 2: Resource Buildouts for P4, P16, and P16(4)

	Portfolio 4						Portfolio 16						Portfolio 16-4					
	Gas	Wind	Solar	Battery	DR	Coal Exit	Gas	Wind	Solar	Battery	DR	Coal Exit	Gas	Wind	Solar	Battery	DR	Coal Exit
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	720	0	0	0	0	0	640	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	-177	0	0	0	0	0	-177	0	0	0	0	0	0
2022	0	0	120	0	0	0	0	0	120	0	0	0	0	0	0	0	0	-177
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	120	0	0	0
2024	0	100	80	0	0	0	0	100	0	0	0	0	0	0	0	0	0	0
2025	0	100	40	30	0	-180	0	100	0	0	0	-180	0	0	0	0	0	0
2026	0	100	200	50	0	0	0	100	200	80	0	0	0	0	0	0	0	-180
2027	0	100	0	0	0	-174	0	100	200	0	0	-174	0	0	0	0	0	0
2028	300	100	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0	-174
2029	0	100	5	0	0	-177	0	100	5	0	0	-177	0	0	40	30	0	0
2030	300	0	5	0	0	0	300	0	0	0	5	0	300	0	0	0	0	-177
2031	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	5	0
2032	111	0	0	0	5	0	0	0	0	0	5	0	0	0	80	10	5	0
2033	0	0	0	0	5	0	0	0	0	0	5	0	0	0	80	20	5	0
2034	111	0	0	0	5	0	0	0	0	0	5	0	0	0	80	20	5	0
2035	0	0	0	0	5	0	0	0	0	0	5	0	111.1	0	0	0	5	0
2036	56	0	0	0	5	0	111	0	0	0	0	0	0	0	0	0	5	0
2037	56	0	0	0	5	0	0	0	0	0	0	0	0	0	320	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	300	440	0	0	0
Nameplate	933	600	1,170	80	30	-708	411	600	1,165	80	30	-708	411	300	1,160	80	30	-708
B2H (2026)							500						500					
Total	**2,105**						**2,078**						**1,773**					

As shown above, Portfolio 16(4) increasingly relies on market purchases beginning in 2020, while the other two portfolios—Portfolios 4 and Portfolio 16—both identify large amounts of solar in 2020 and therefore rely less on market purchases. Portfolios 4 and 16 continue to identify large amounts of renewable resource additions through 2029, reducing their reliance on market purchases as compared to the preferred portfolio. However, the preferred portfolio experiences a major dip in market purchases in 2030, when a 300 MW resource is added. Thus, Portfolio 16(4)'s uptick in market purchases corresponds to the relatively limited resource buildout associated with that portfolio, as compared to the significant new resources associated with both Portfolio 4 and Portfolio 16.

In sum, ***the differences in market purchases among the three portfolios merely reflect different resource buildouts produced by the LTCE modeling parameters***. The model was not producing anomalous results and the Company was not making undisclosed adjustments to B2H portfolios.

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B. Net Present Value Variance as a Measure of Risk

Staff questions whether Idaho Power's evaluation of variations in net present value ("NPV") provide a useful measure of risk.[72] Staff also asks the Company to describe how the two sets of portfolios were selected from this analysis for further manual adjustment.[73]

The Company conducted its NPV variance analysis by evaluating each of the 24 WECC-optimized portfolios under the following four scenarios: (1) Planning Gas-Planning Carbon; (2) High Gas-High Carbon; (3) High Gas-Planning Carbon; and (4) Planning Gas-High Carbon. Of these four options, the Company believes that the NPV under the Planning Gas-Planning Carbon scenario reflects the most likely expected costs (*i.e.*, the planning case for both variables). While the Company's NPV variance analysis did not weight the relative likelihood of the scenarios, it nonetheless provides valuable insight into the range of cost risk for each portfolio. By analyzing the performance of each portfolio under this range of future conditions, the Company identified the corresponding range of price risk. For example, the NPV for Portfolio 14 under the Planning Gas-Planning Carbon scenario was $6.1 billion and the same portfolio under the High Gas-High Carbon scenario was $9.7 Billion—a $3.6 billion difference associated with these two variables. The results of the Company's NPV variability analysis can be found in Table 9.3 of the IRP, and is included below for ease of reference.[74]

[72] Staff's Opening Comments at 7 ("Staff is concerned with the use of variance across four scenarios to represent an informative measure of 'risk.'").
[73] Staff's Opening Comments at 7 ("[I]t is unclear to Staff why portfolios 3 and 15 . . . were not chosen for additional analysis when graphically they appear to be as viable as portfolios 4 and 16.").
[74] Idaho Power's Amended 2019 IRP at 106 (Table 9.3).

Table 3: 2019 IRP WECC-optimized 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 1	$6,262,350	$6,983,921	$8,615,746	$9,785,216
Portfolio 2	$6,180,898	$7,050,988	$8,268,640	$9,484,077
Portfolio 3	$6,743,579	$7,210,723	$7,758,806	$8,317,985
Portfolio 4	$6,711,725	$7,186,392	$7,764,683	$8,353,585
Portfolio 5	$6,247,134	$6,965,305	$8,640,298	$9,783,543
Portfolio 6	$6,295,506	$6,991,122	$8,671,032	$9,767,701
Portfolio 7	$6,997,047	$7,335,052	$7,883,018	$8,298,494
Portfolio 8	$6,921,411	$7,308,725	$7,845,686	$8,329,757
Portfolio 9	$6,351,648	$6,960,567	$8,563,652	$9,640,438
Portfolio 10	$6,857,192	$7,075,085	$8,319,929	$9,006,307
Portfolio 11	$7,936,126	$7,890,594	$8,512,277	$8,559,033
Portfolio 12	$7,866,893	$7,851,159	$8,408,693	$8,503,484
Portfolio 13	$6,298,486	$7,084,234	$8,966,855	$10,126,243
Portfolio 14	$6,131,430	$7,081,861	$8,426,982	$9,721,956
Portfolio 15	$6,484,416	$7,185,644	$7,780,477	$8,630,057
Portfolio 16	$6,632,764	$7,205,140	$7,802,154	$8,516,159
Portfolio 17	$6,306,492	$7,084,799	$8,943,907	$10,093,639
Portfolio 18	$6,155,638	$7,057,686	$8,641,689	$9,775,039
Portfolio 19	$6,770,655	$7,287,389	$7,878,895	$8,514,255
Portfolio 20	$6,852,642	$7,311,787	$8,080,079	$8,740,492
Portfolio 21	$6,483,530	$7,074,327	$8,795,307	$9,733,627
Portfolio 22	$6,511,244	$7,064,598	$8,722,004	$9,634,701
Portfolio 23	$7,230,853	$7,585,172	$8,151,311	$8,574,738
Portfolio 24	$7,380,489	$7,681,075	$8,228,451	$8,631,068

Having performed this price variability analysis, the Company identified four portfolios for further manual analysis and adjustment based on which provided the best combination of expected costs and associated risks, consistent with the Commission's IRP guidelines.[75] To achieve this goal, the Company balanced the NPV of each portfolio under the planning future with the cost variance under the four different scenarios—that is, the lowest cost and the

[75] The Commission's IRP Guideline 1(c) requires the Company to develop a portfolio "with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."

lowest price variability—to identify two sets of portfolios. Each set contained one portfolio with B2H and one portfolio without B2H, yielding four total portfolios.

Portfolio 4 and Portfolio 16 were selected as the best paired grouping with the least amount of four-scenario NPV variance, while Portfolio 2 and Portfolio 14 were selected as the best paired grouping with respect to the expected cost under the planning case for both gas and carbon prices. While the Company could have selected different pairings of portfolios, the results of the manually adjusted portfolios indicate that the results would have been similar due to the impacts of the subsequent load and resource balance analysis. For example, the Company chose Portfolio 14 and Portfolio 16 to manually adjust, yet the preferred portfolio results resemble those in Portfolio 15. These results suggest that excluding Portfolios 3 and 15 from the manual process did not significantly impact the results.

C. Manual Adjustments

Staff questions three aspects of the Company's use of manual portfolio adjustments. First, Staff asks whether Idaho Power made additional manual adjustments beyond assessing the impacts of different Jim Bridger retirement dates, noting that the Company describes a series of qualitative risks that also seem to have influenced the Company's manual adjustments.[76] Second, if adjusting these retirement dates was the only change performed, Staff asks how such adjustments led the Company to remove both Franklin Solar and a Request for Proposals ("RFP") from the Amended IRP action plan. Third, Staff questions why Idaho Power postponed pursuit of further demand response, and whether this change was the result of the Company's manual adjustments.[77]

Idaho Power can confirm that the manual adjustments made in the portfolio analysis were limited to evaluating different exit dates from Jim Bridger, while preserving a 15-percent

[76] Staff's Opening Comments at 8 ("[I]t is unclear whether manual adjustments were made to the WECC-optimized portfolios beyond Jim Bridger retirement dates.").
[77] Staff's Opening Comments at 7-8.

planning margin.[78] Franklin Solar and the RFP were both removed from the action plan in the Amended 2019 IRP for reasons unrelated to the manual portfolio adjustments. Franklin Solar was removed from the stack of available resources within the LTCE model for the Amended IRP because the Company had already elected not to exercise its right and option to purchase the 100 MW of additional output related to Franklin Solar. This decision was made between the filing of the original IRP and the filing of the Amended IRP. The RFP was similarly removed between the original IRP and the Amended IRP, and the Amended IRP's reference to an RFP is an error. Idaho Power notes that this error was previously communicated to Staff and is noted elsewhere in Staff's comments.[79]

Additionally, the timing of demand response was not further refined as a part of the manual portfolio development process, and therefore is not tied specifically to the evaluation of Jim Bridger exit dates. Demand response was included within the WECC-optimized portfolios and was, like other future resources, influenced by the assumption changes described in the Executive Summary of the Amended IRP. As discussed in more detail below, demand response is used to minimize or delay the need to build new on-peak supply-side resources. In this case, the Company's preferred portfolio includes new demand response in 2031.[80] Apart from the Jackpot PPA addition in year 2022, only two resource additions precede the development of additional demand response. These two resources, identified for inclusion in 2029 and 2030, could not be deferred or offset with demand response. The Company intends to continue exploring innovative ways to leverage demand response in the

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[78] Idaho Power's Amended 2019 IRP at 109.

[79] Staff's Opening Comments at 4 ("There is also one additional Action Item listed in the Amended IRP: 'Procure or construct resources resulting from RFP (if needed).' Staff asked about this in a data request because the preferred portfolio made no mention of a request for proposal (RFP), nor was there any discussion of an RFP anywhere in the Amended IRP. The Company responded that this Action Item should be disregarded and was inadvertently left in from the IRP filed back in June 2019.").

[80] Idaho Power's Amended 2019 IRP at 125

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Portland, Oregon 97205

2021 IRP.

D. Stochastic Risk Analysis

STOP B2H claims that Idaho Power's stochastic risk analysis is inadequate because the Company did not include carbon cost impacts as one of the stochastic variables, and further claims that such analysis would have shown that B2H increases the expected cost in nine of the twelve non-B2H portfolios, while increasing the downside risk for all twelve portfolios.[81] STOP B2H's criticism is not well founded. First, Idaho Power selected the appropriate variables for stochastic analysis. And second, the Company adequately considered the impacts of potential carbon pricing in the portfolio analysis process.

Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and the degree to which the variable can affect the results of a given analysis. Here, Idaho Power's stochastic risk analysis examined three factors: (1) natural gas price changes, (2) customer load fluctuations, and (3) hydroelectric variability.[82] Each of these three factors can have a significant degree of forecasting variability and a strong impact on portfolio results. Going forward, Idaho Power is open to considering carbon cost as an additional stochastic evaluation in the future. However, in this case, Idaho Power thoroughly examined the possible carbon price fluctuations in the modeling process.

Once the initial WECC-optimized portfolios were generated, Idaho Power evaluated each portfolio to determine the impact of high gas prices, high carbon costs, or both. As described above, this approach resulted in four different sets of price assumptions: (1) Planning Gas-Planning Carbon; (2) High Gas-High Carbon; (3) High Gas-Planning

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[81] STOP B2H's Amended Opening Comments at 9 ("[T]he addition of B2H to nine of the twelve Portfolios INCREASES both the expected NPV cost to ratepayers, and the risk – as measured by the standard deviation — to those customers, when compared to identical Portfolios without B2H.") (emphasis omitted); *id.* at 10 ("However, in all twelve of Portfolios 13-24, adding B2H increases the standard deviation (downside risk) of the same portfolio without B2H.") (emphasis omitted).
[82] Idaho Power's Amended 2019 IRP at 111-113.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

Carbon; and (4) Planning Gas-High Carbon. Based on this analysis, Idaho Power selected four portfolios for further adjustment.

STOP B2H attempts to modify the Company's analysis to reflect the likelihood of carbon risk by simply averaging the Company's scenario NPVs. This approach assumes that measuring the impact of different carbon costs is the same as measuring the *likelihood* of such impacts occurring. STOP B2H's analysis conflates these two concepts by assuming that each different portfolio's NPV has an equal likelihood of occurrence. While statistics that identify the likelihood of each future are not available, Idaho Power reasonably expects that the likely future value of both carbon and gas are reflected in the planning cases. Indeed, the high gas price and carbon cost cases reflect, at the IRPAC's direction, *extreme* values to provide a wide range of possible futures to test the Company's portfolios. For example, the "high gas" cost assumption was based on the 2018 EIA low oil and gas assumption. EIA has since released a 2019 natural gas price forecast with a "high gas" price forecast that is nearly 20 percent *lower* than the 2018 "high" gas price forecast. In other words, the "high gas" price assumption in the 2019 IRP is higher than EIA is currently forecasting in the highest of price conditions, and is therefore *extremely* conservative. By extension, portfolio cost information based on "high gas" conditions has a very low likelihood of occurring. Similarly, the "high carbon" cost assumption reflects the highest cost assumption in the California Energy Commission's Integrated Energy Policy Report, ensuring that results from carbon modeling were extremely conservative. STOP B2H's analysis, in contrast, fails to recognize the relatively low likelihood that these high cost cases will actually occur.

In sum, while Idaho Power is open to considering adding carbon costs as a stochastic variable in the future, the Company's portfolio modeling analysis adequately accounted for possible carbon price impacts on the Company's portfolios.

V. MARKET PURCHASES

Renewable Northwest and STOP B2H comment on the Company's reliance on market purchases to meet future need—specifically, (1) market depth (or "availability"), (2) market purchase characteristics, and (3) market price volatility. As explained below, there is sufficient market availability to support Idaho Power's future loads. Additionally, the Company appropriately addressed the characteristics and risks associated with market purchases as part of its IRP analysis.

1. Market Availability is Sufficient to Support Idaho Power's Future Load.

Both Renewable Northwest and STOP B2H note the Company's plan to rely on market purchases to meet a portion of the Company's future peak load, and request that Idaho Power provide more detail to show that there is sufficient market depth to support the Company's approach.[83] Renewable Northwest is generally supportive of Idaho Power's conclusion that additional transmission will increase the Company's access to market purchases. However, for future IRP cycles, Renewable Northwest asks that the Company provide more detail on "how well market availability aligns with the Idaho Power's expected system peaks and capacity needs."[84]

While Idaho Power appreciates Renewable Northwest's support of the Company's efforts to increase market access, the Company notes that Appendix D: B2H Supplement discusses liquidity and market sufficiency risk in some detail.[85] At a high level, the B2H Supplement explains that (1) B2H connects the Pacific Northwest's winter-peaking system with Idaho Power's summer-peaking system, thus allowing both to benefit significantly from the increased transmission capacity; and (2) the Mid-C Market exhibits all characteristics of a successful electric trading market and, with adequate transmission, may be relied upon to

[83] STOP B2H's Amended Opening Comments at 7; Renewable Northwest's Opening Comments at 5.
[84] Renewable Northwest's Opening Comments at 5.
[85] Idaho Power's Amended 2019 IRP, App. D at 6-10 and 54.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

serve Idaho Power's customers. In addition, Idaho Power has provided contextual data demonstrating recent market availability in a confidential response to Staff's Data Request No. 33, which summarizes Idaho Power's firm purchases during the Company's summer peak months of July and August between 2016-2019 from the Pacific Northwest. [redacted] Idaho Power expects that these counterparties will continue to transact at Mid-C in the future and firm energy will continue to be available. [86]

Finally, Idaho Power has also provided information showing all dispatchable resources expected to be available in 2025 in the Northwest and Canada.[87] The total capability of all the resources is over 73,000 MW (compared to Idaho Power's 500 MW summertime interest in B2H). As discussed in the Market Sufficiency Risk section of the Company's Amended IRP, the Northwest and Canadian regions are winter-peaking—meaning that surplus resource capability is available for summer demand. A 2025 list was compiled because a base case for a later year was not readily available.

Despite this information supporting the adequate availability of market purchases, STOP B2H challenges whether there is sufficient "physical" market depth to support the Company's future long-term reliance on market purchases.[88] Specifically, STOP B2H claims that, as a primarily financial market, the Mid-C market frequently encounters physical constraints.[89] To demonstrate the adequacy of the market's "physical" depth, STOP B2H asks that the Company be required to identify the specific generating resource behind each hourly purchase in its portfolios, both with and without B2H.[90]

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[86] To be clear, firm purchased energy can include intermittent renewable resources if the selling party takes steps to "firm" the product. [redacted]

[87] Idaho Power's Response to Staff's Data Request No 33, Attachment 2 ("2025 Northwest Gen").

[88] STOP B2H's Amended Opening Comments at 7.

[89] STOP B2H's Amended Opening Comments at 7.

[90] STOP B2H's Amended Opening Comments at 8.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

STOP B2H is simply incorrect that the Mid-C lacks adequate physical resources to meet demand. As explained above, this statement is contrary to the market data that Idaho Power sees every day. As a practical matter, the existence of a financial market depends on sufficient daily physical activity. In other words, without physical activity, which allows for a reliable index, no financial products can be traded.[91] Importantly, while there is no support for STOP B2H's concern that energy markets at Mid-C will be limited, it is inarguable that the *transmission system* between Mid-C and Idaho Power is constrained—driving the need for transmission system projects like B2H.[92]

In aggregate, the Company's IRP and supplemental document disclosures clearly demonstrate that there will be sufficient resources to import over the B2H line to support the Company's summer peaking load in the future.

2. Idaho Power Adequately Addressed the Characteristics of Market Purchases.

Renewable Northwest also asks that in future IRP cycles the Company provide "more granularity regarding the characteristics of market purchases as a resource[.]"[93] Similarly, STOP B2H asks that Idaho Power "more clearly characterize" the attributes of market purchases, and claims that Idaho Power inappropriately assumes that market purchases are "the simple equivalent of a virtual gas-fired plant[.]"[94]

As Idaho Power explained in its IRP, market purchases are a valuable and versatile resource that allow the Company to take advantage of price differences across regions.[95] The Company provided a table showing differences between the resource characteristics,

[91] Idaho Power's Amended 2019 IRP, Appendix D provides additional information on Mid-C and associated modeling.
[92] STOP B2H's proposal to identify the specific generating resource behind each hourly purchase in the Company's portfolios is impractical because AURORA is not able to identify the specific resource associated with a market purchase. As a result, Idaho Power is not able to extract the information requested by STOP B2H.
[93] Renewable Northwest's Opening Comments at 5.
[94] STOP B2H's Amended Opening Comments at 7.
[95] Idaho Power's Amended 2019 IRP, App. D at 9.

including dispatchability, flexibility, variability, and price risks.[96] Thus, the Company's analysis recognizes that there are strengths and weaknesses to every resource, and evaluates these costs and benefits accordingly.

3. Idaho Power Adequately Assessed the Risks of Market Price Volatility.

STOP B2H argues that Idaho Power has not assessed the risk of market price volatility and uncertainty,[97] and claims that the Company's market purchase prices are, due to the AURORA model's "simplistic" forecasts, "all based upon a forecast of average monthly gas prices[.]"[98] STOP B2H is mistaken because (1) Idaho Power clearly assessed the price risks of market purchases; and (2) the AURORA model is far from a simplistic tool for forecasting gas prices.

First, the Company specifically addressed market price volatility as one of the major qualitative risks in Idaho Power's Amended IRP.[99] Specifically, the Company explained that the detailed stochastic and portfolio cost analyses indirectly assessed the impact of wholesale electric market price variations, as follows:

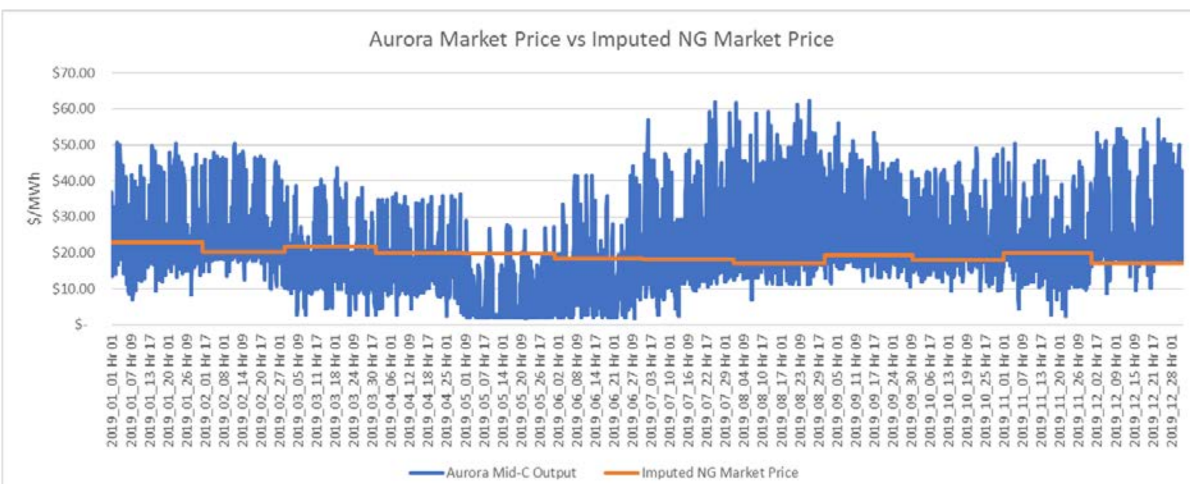
> Idaho Power emphasizes that wholesale electric market prices are not specified inputs to the AURORA model, but rather are output by the model in response to various factors and are strongly driven by positive correlations with natural gas price and carbon cost, and a negative correlation with hydro condition. Thus, the risk analyses performed by Idaho Power are considered to study the relative exposure of the IRP resource portfolios to the studied inputs (e.g., natural gas price), and by extension to wholesale electric market prices output by the AURORA model.[100]

Second, STOP B2H is incorrect that the AURORA model is a simplistic representation of the cost of dispatching available resources at the margin, and that market prices are simply

[96] Idaho Power's Amended 2019 IRP, App. D at 11 (Table 2).
[97] STOP B2H's Amended Opening Comments at 8.
[98] STOP B2H's Amended Opening Comments at 7.
[99] Idaho Power's Amended 2019 IRP at 117.
[100] Idaho Power's Amended 2019 IRP at 53.

the result of average monthly gas prices.[101] On the contrary, AURORA is a price forecasting and analysis software based on the fundamentals of the competitive electric market. AURORA applies economic principles and dispatch simulations to model the relationships of supply, transmission, and demand for electric energy to forecast market prices. To be clear, monthly gas prices are not used as the sole predictor of electric market prices in AURORA for every hour. The electric market price in AURORA is determined on an hourly basis, examining *all* resources during that hour. The marginal resource for that hour determines the marginal price, which can vary every hour. To illustrate this distinction, Figure 3, below, shows the AURORA Market price for Mid-C compared to an imputed natural gas market price. The imputed natural gas market price used historical Henry Hub natural gas prices applied to a CCCT resource.[102] As this figure shows, the AURORA electric market price varies much more than the imputed natural gas market price.

Figure 3: AURORA Mid-C vs Imputed Natural Gas Market Price



Thus, Idaho Power has clearly and adequately analyzed market price variability and risk as part of this IRP.

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[101] STOP B2H's Amended Opening Comments at 7-8.
[102] Idaho Power's Amended 2019 IRP, App. C at 23.

VI. SUPPLY SIDE RESOURCES

A. Jim Bridger

Staff,[103] CUB,[104] and Sierra Club[105] provide a number of comments on the Jim Bridger retirement dates in the Company's preferred portfolio. Specifically, the parties (1) ask the Company to specify which units are planned for retirement on which date; (2) note that the Company's planned unit retirement dates are different from the retirement dates selected by PacifiCorp in its 2019 IRP; (3) query why the Company's plan to exit a second Bridger unit is tied to B2H's 2026 in-service date; and (4) ask the Company to perform additional sensitivity analysis using the retirement dates proposed by PacifiCorp in that company's 2019 IRP.[106]

Idaho Power analyzed potential Bridger retirement dates at two stages of the Company's portfolio analysis. First, the LTCE capability of Aurora for the 2019 IRP allowed the model to evaluate generation units for economic retirement prior to baseline retirement dates. The 24 WECC-optimized portfolios, as shown in Figures 8.3 and 8.4 in the 2019 Amended IRP, demonstrate that in many cases early coal unit exits were selected to be cost-effective. The Company then selected a subset of top-performing WECC-optimized portfolios and manually adjusted them with the objective of further reducing Idaho Power-specific portfolio costs. In total, 20 additional portfolio runs were performed that tested various Jim Bridger exit date sensitivities.

The additional step of developing 20 manual portfolios provided Idaho Power the opportunity to evaluate multiple timing scenarios for Jim Bridger exit dates, shown below.[107] Several of the dates are later than those in the preferred portfolio.

[103] Staff's Opening Comments at 8-9.
[104] CUB's Opening Comments at 8-9.
[105] Sierra Club's Opening Comments at 2-4 (Apr. 2, 2020).
[106] Staff's Opening Comments at 9.
[107] Idaho Power's Amended 2019 IRP at 109 (Table 9.4).

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

Table 4: Jim Bridger exit scenarios

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
2022	2022	2022	2022	2023	2024
2026	2026	2028	2026	2026	2026
2034	2028	2034	2028	2028	2028
2034	2034	2034	2030	2030	2030

Tables 9.5 through 9.8 in the Amended IRP show the cost changes from the WECC-optimized result and the manually adjusted Bridger exit scenarios for Portfolios 2, 4, 14, and 16. The results of the analysis demonstrate that, under most gas/carbon price scenarios, it is cost effective to exit the coal units early while ensuring system reliability and sufficiency.

1. Jim Bridger Retirement by Unit

Staff and CUB note that Idaho Power did not specify which Jim Bridger units will be retiring at which dates.[108] As Idaho Power has explained, the Company has not identified which units will retire at which date.[109] However, Idaho Power believes that Jim Bridger units 1 and 2 will most likely be the first units to retire due to factors such as their relative condition, efficiency, and outage schedules. As between Units 1 and 2, however, the timing is less clear because the units are similar.

2. Jim Bridger Retirement Coordination with PacifiCorp

Staff and CUB note that the unit retirement dates in the Company's preferred portfolio are different from the dates in PacifiCorp's 2019 IRP.[110] To be clear, the preferred portfolio identifies those dates that would most likely achieve the least-cost, least-risk result for Idaho Power's customers. However, these target dates are dependent on, among other factors, successful coordination with PacifiCorp. Idaho Power therefore anticipates that the Company's Amended 2019 IRP analysis will be used as the basis for initial negotiations.

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[108] Staff's Opening Comments at 9; CUB's Opening Comments at 8.
[109] *See* Staff's Opening Comments at 9 (describing the Company's response in discovery).
[110] Staff's Opening Comments at 9; CUB's Opening Comments at 8.

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Portland, Oregon 97205

To date, Idaho Power and PacifiCorp have conducted only high-level discussions regarding potential retirement dates consistent with each Company's preferred portfolios regarding the Jim Bridger units. Both companies will continue discussions as each proceeds with its planning process for the 2021 IRP. As these discussions are just beginning, it is difficult to chart a clear path towards resolution of the different retirement dates. Nonetheless, Idaho Power's exit from the Valmy plant demonstrates that the Company can successfully cease participation in its ownership share of coal units, even when its partner favors different retirement dates.

Moving forward, Sierra Club asks that Idaho Power commit to updating the Commission on the negotiations with PacifiCorp by the end of 2020.[111] Idaho Power is amenable to this request.

3. Jim Bridger Retirement and B2H

CUB states that the Company has not explained the connection between a second Bridger unit retirement and the 2026 anticipated completion of B2H.[112] To clarify, retiring a second Bridger unit will require a replacement resource in order to avoid a significant system capacity deficiency. The preferred portfolio identifies B2H as the lowest-cost and lowest-risk replacement resource. Thus, the cost-effective replacement of a second Bridger unit is connected to B2H successfully being placed in service.

4. Jim Bridger Retirement Sensitivity Analysis

Staff asks the Company to perform additional sensitivity analysis evaluating the Jim Bridger retirement dates described in PacifiCorp's 2019 IRP.[113] However, a sensitivity analysis with retirement dates that precisely match PacifiCorp's would result in the Company's *extension* of the life of Units 3 and 4 from current operating assumptions. Idaho Power's

[111] Sierra Club's Opening Comments at 4.
[112] CUB's Opening Comments at 8
[113] Staff's Opening Comments at 9.

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Portland, Oregon 97205

existing operating assumptions that are included as the starting point for portfolio modeling reflect an end-of-life date for all Jim Bridger units at 2034. In contrast, PacifiCorp's latter two units are described as retiring in 2037. While the Company understands Staff's desire for additional modeling, it does not believe a scenario that considers the *extension* of existing coal resources to be a likely future, in part based on the policy considerations of both Idaho Power and the Commission. Therefore, to balance the likelihood of future resource actions with the supplemental analysis requested by Staff, the table below provides a review of the sensitivity analysis performed by the Company utilizing Portfolio 14(3), which has the most similar Jim Bridger exit dates to PacifiCorp's preferred portfolio without extending the life of any unit beyond the Company's current end-of-life assumptions. A comparison between these two sets of retirement dates and the Company's preferred portfolio is shown in the table below.

Table 5: Jim Bridger exit scenarios – Idaho Power and PacifiCorp

Jim Bridger	PacifiCorp	Idaho Power P14(7)	Idaho Power P14(3)
Unit 1	2023	2022	2022
Unit 2	2028	2026	2028
Unit 3	2037	2028	2034
Unit 4	2037	2030	2034
	NPV Cost ($ x 1,000)	**$6,003,939**	**$6,068,301**
	Difference	**($64,362)**	

The table above demonstrates that moving Jim Bridger unit retirements to dates comparable to those identified by PacifiCorp results in increased costs compared to Idaho Power's preferred portfolio.

B. Capacity Value for Variable Resources

Staff questions whether the Company's approach to determining the capacity value of solar and wind complies with the stipulation entered in UM 1719 and approved by the

Commission in Order No. 16-326.[114] The Company applied different approaches to determine the capacity value for solar and wind, and so Staff's concerns are addressed separately for each resource.

1. Capacity Value of Solar

Staff asserts that Idaho Power's approach to determining the capacity value of solar does not comply with Order No. 16-326 because the Company's analysis purportedly considers solar's contribution to preventing loss of load events during only the 100 highest load hours of the year.[115] While Idaho Power recognizes that its approach to calculating solar's capacity value has changed, the Company believes that the National Renewable Energy Laboratory's ("NREL") approach used in this proceeding substantially complies with the parties' stipulation and the Commission's order because (1) the Company clearly communicated to both other parties and the Commission concerning the nature and reason for this change; (2) an alternate approach was plainly necessary to account for the dramatic increase in solar penetration in a few short years, while simultaneously modeling significant additional solar capacity expansions in this IRP; (3) the Company was unable to implement the Effective Load Carrying Capability ("ELCC") method due to lack of data required by that model; and (4) the NREL model is a highly regarded, rigorously supported, third-party method that is closely related to the ELCC and is based on all hours in a year. Thus, the Company believes that it has achieved a high-quality approach to modeling solar's capacity value while allowing the Company to effectively evaluate substantial solar capacity expansion.

By way of background, in Order No. 16-326, the parties stipulated that utilities could use either a Capacity Factor ("CF") approximation method or the ELCC method to estimate solar's capacity value, so long as the utilities prepared contribution estimates based on an

[114] Staff's Opening Comments at 16.

[115] *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 (Aug. 26, 2016).

assessment of all hours in a year. In addition, utilities were free to interpolate or extrapolate from the calculated values as needed,[116] and Idaho Power in particular could continue to apply its own "approximation" approach to assessing solar's capacity value, so long as the Company's Loss of Load Probability ("LOLP") was similarly based on solar's contribution during all hours of the year.[117] As the Company explained at the time, Idaho Power relied on this approximation approach in part because there was no actual on-system solar data on which to base more detailed capacity calculations.[118] While other parties, including Staff, generally favored the ELCC method,[119] this approach requires extensive utility-specific generation and load data that the Company did not—and still does not—have.[120] However, Idaho Power's existing approximation methodology did not account for solar's changing capacity value as the share of solar on the Company's system changes, meaning that the Company's ability to accurately value solar's capacity contribution could be severely hampered if Idaho Power's system faced a sudden upswell of new solar power. This is precisely what has happened.

Since 2016, Idaho Power has experienced a surge of new solar projects in its service territory, going from zero solar capacity to approximately 289 MW of capacity in a single year. Indeed, as the Company began preparing for its 2019 IRP, it became clear that solar could continue to grow at a rapid pace, as some of Idaho Power's modeled portfolios include over 1,000 MW of new solar generation. In order to understand how new solar would contribute to the Company's capacity needs under the 2019 IRP's capacity expansion approach, accurate solar capacity valuation was essential. Specifically, it became vital for Idaho Power to account

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[116] Order No. 16-326, App. A at 3.
[117] Order No. 16-326 at 6.
[118] 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[.]").
[119] Order No. 16-326 at 3.
[120] Docket UM 1719, Idaho Power/100, Haener/13.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

for the shifts in capacity value caused by increased solar penetration. These shifts occur because times of year that might initially have had relatively high LOLP (*e.g.,* midsummer days) would, with increased solar generation, gradually come to have relatively low LOLP as more solar generation provided peak output during those times. Thus, accurate modeling would account for shifting hours of high LOLP as solar penetration increases.

While the Company recognized the need to apply a more nuanced model to assess solar's capacity value, the Company chose not to use the ELCC method for two reasons. First, the ELCC method relies on the rated nameplate capacity of generation and the forced outage rate, for which 3-5 years of operational data is essential. The Company still lacks adequate data to rely on the ELCC methodology, as solar projects had been operating on the Company's system for less than two years by the time the Company began its 2019 IRP analysis. Second, the ELCC method still does not adjust for solar's changing capacity value as the total amount of solar on the Company's system increases. Given Idaho Power's unique experience with a rapid spike in solar development, it was crucially important to incorporate a more dynamic methodology.

Ultimately, the Company determined that the best approach to model solar's capacity value would be to use the NREL method, which is a variation of the ELCC. The Company brought this proposal to the Company's IRPAC on December 13, 2018, and understood that the IRPAC fully supported the Company's new and more nuanced approach. The Company also highlighted that it was transitioning to the NREL method for calculating the capacity value of solar in the Company's IRP Update Report, filed on January 28, 2019.[121]

Importantly, this new NREL method conforms to the stipulation's requirement to consider all 8,760 hours in a year. The NREL methodology begins with an assessment of all hours in a year to arrive at the 100 highest *net load* hours, which are the 100 highest load

[121] Docket LC 68, Idaho Power Company IRP Update Report at 16 (Jan. 28, 2019).

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

hours, minus preexisting solar capacity during those hours.[122] Given that the 100 highest *net load* hours change with increasing solar penetration, the Company's model was not focused on an isolated 100 hours. This dynamic modeling approach allowed the Company to account for changes in total solar capacity over time, which in turn could help shape the capacity value of incremental solar additions.

Moving forward, Idaho Power remains committed to continuing to improve its modeling for the capacity value of solar, and welcomes other parties' and Staff's comments and suggestions.

2. Capacity Value of Wind

Staff states that the Company's IRP does not provide sufficient detail to determine if the Company is in compliance with Order No. 16-326, and thus asks the Company to explain how its approach is consistent with the parties' stipulation in that docket.[123]

The stipulation in Order No 16-326 allows the use of ELCC or CF approximation to calculate capacity values. In compliance with the stipulation, Idaho Power used a CF approximation method to calculate wind's capacity factor, with the addition of a LOLP analysis based on all hours in a year. The method was developed by modeling wind based on historical data available at the time.[124] Idaho Power has used this same methodology to evaluate wind CFs since the 2013 IRP.

Idaho Power is currently performing an update to the Variable Energy Resource ("VER") integration study. The results of the study are anticipated to help Idaho Power

[122] As NREL has explained in a rigorous report, the 100 highest *net load* hours reliably represent solar's annual capacity contribution. Nat'l Renewable Energy Laboratory, "8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models" at 14 (Aug. 2017) (noting that the approach captures "load and VG interactions across all 8760 hours of the year, with a specific focus on the top 100 net load hours as a proxy for the highest LOLP hours"), *available at:* https://www.nrel.gov/docs/fy17osti/68869.pdf.
[123] Order No. 16-326, App. A.
[124] Idaho Power used AURORA to check the LOLP for all hours in a year.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

reassess the best method for evaluating the capacity value of wind in the 2021 IRP.

C. Natural Gas

Staff questions the inclusion of new natural gas resources added in 2030 and 2035, particularly given the Company's goal of 100 percent clean energy by 2045—thus potentially resulting in early retirement of these units and stranded assets.[125] As discussed further in Section IX.B.3 below, Idaho Power included the natural gas resources in the later years of the planning horizon as surrogate resources, reflecting the attributes and costs that the Company must target to be cost-effective for customers. As such, Idaho Power did not include early exit costs for natural gas resources in its portfolio evaluation. However, Idaho Power files an IRP every two years and the Company is fully committed to evaluating resources that move Idaho Power closer to its goal of 100 percent clean energy by 2045. Certainly, Idaho Power would anticipate issuing an RFP as the need for such resources nears.

D. Wind

Staff asks the Company to explain why the 2019 IRP's estimate for the levelized cost of energy ("LCOE") of Wyoming wind resources ($94/MWh) is so much higher than the economic research literature ($34.10-$54/MWh) and estimates from PacifiCorp's IRP (which, thanks to tax credits, present affirmative cost savings).[126]

In general, LCOE calculations are influenced by factors such as capital costs, financing costs, tax credits, maintenance costs, capacity factors, degradation assumptions, and depreciable life.[127] Here, Idaho Power relied on the 2018 NREL Annual Technology Baseline ("ATB") for a report on estimated capital costs (in 2023 dollars). Capital costs from the NREL ATB were in-line with capital costs from other economic research literature at the time. Given

[125] Staff's Opening Comments at 18.
[126] Staff's Opening Comments at 18.
[127] Idaho Power's Amended 2019 IRP, App. C pages 23-24 detail the major cost assumptions in the LCOE calculation for each supply-side resource considered.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

the impending expiration of wind tax credits and the lack of a near-term resource need, the cost assumptions for wind do not reflect any PTCs. Additionally, to better reflect the actual cost of a resource, Idaho Power included estimated non-fuel O&M, necessary transmission upgrade costs, and Idaho Power's wind integration costs in the LCOE calculations.[128] Lastly, Idaho Power applied its embedded financing cost assumptions to reflect likely financing costs.

Thus, Idaho Power's LCOE for wind resources may have differed from extant literature and PacifiCorp's LCOE of wind resources for a number of reasons, including the relative valuation of wind tax credits, capital cost estimates, integration costs, transmission upgrade costs, anticipated project life, financing assumptions and capacity factor estimates.

E. Combined Solar and Storage

STOP B2H discusses the ancillary value of resource combinations such as combined solar and storage, and argues that these resource combinations must be included in the IRP.[129] STOP B2H's concerns are unfounded because the Company's LTCE analysis examined multiple solar variations, including solar-battery combinations and solar with targeted siting for grid benefits.[130]

The LTCE tool in AURORA evaluates all resource attributes during a buildout process to determine which resource combinations benefit the system. The resource options considered in Idaho Power's analysis included solar, solar plus storage, and stand-alone storage[131]—all of which were included as new resource options in the 24 WECC-optimized portfolios, as well as for the 20 manually adjusted portfolios.

The Company agrees with STOP B2H that combined solar and battery options provide useful ancillary benefits. For instance, the Solar PV – Utility Scale 1-Axis Tracking with a 4-

[128] Transmission and integration costs generally are not reflected in third-party published LCOEs.
[129] STOP B2H's Amended Opening Comments at 55-56.
[130] Idaho Power's Amended 2019 IRP App. C at 23.
[131] Idaho Power's Amended 2019 IRP App. C at 23.

hour Battery option allows the battery to provide both regulation services and dispatchability. This system also uses low-cost solar energy to charge the battery. Similarly, the Solar PV – Targeted Siting for Grid Benefit resource may be sited to offset additional distribution investment and provide voltage control. The stand-alone battery system provides the same ancillary services described above, as well as allowing the Company to store energy from the grid. Indeed, the Company's inclusion of these other benefits of solar and storage significantly improves on the 2017 IRP resource analysis. The Company intends to continue refining its evaluation of solar and storage in future IRPs.

F. Combined Heat and Power

STOP B2H recommends that the Commission encourage Idaho Power and others to explore increased combined head and power ("CHP") systems, describing such projects as offering a range of benefits and "little downside[.]"[132] Noting that Idaho Power's service area currently has 20.9 MW of CHP resources, STOP B2H claims that CHP could potentially provide an additional 500 MW to Idaho Power's system.[133]

As a general matter, Idaho Power agrees with STOP B2H that CHP resources can provide important benefits. CHP resources can be highly efficient, are generally located near load centers (thereby potentially avoiding the need for distribution investments), and can provide a local economic contribution by reducing costs for the CHP host. Idaho Power called out these important benefits in the Company's Amended IRP.[134]

Unfortunately, modeling CHP resources in an IRP is challenging due to the substantial variation among CHP projects. STOP B2H seems aware of this difficulty, as its comments cite a passage from the Company's IRP describing the difficulties of modeling CHP

[132] STOP B2H's Amended Opening Comments at 37-38.
[133] STOP B2H's Amended Opening Comments at 38.
[134] Idaho Power's Amended 2019 IRP at 51.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

technologies.[135] However, this modeling difficulty should not be interpreted as reluctance on the part of Idaho Power to evaluate potential CHP opportunities.

Indeed, Idaho Power remains committed to working with interested customers to design economical CHP systems, as noted in the Company's IRP.[136] Over the last several years, Idaho Power has engaged with multiple customers regarding potential CHP opportunities. While these conversations have not yet resulted in operating projects, the Company reaffirms its commitment to working with customers to identify potential CHP opportunities, particularly as technology and economics change over time.

In sum, given the important variations in CHP projects, as well as the Company's ongoing efforts and clear commitment, STOP B2H's recommendation for generalized analysis is unfounded.

G. Reserve Requirements

Sierra Club asserts that Idaho Power overestimates the magnitude of reserves that the Company needs to carry to serve future customers, resulting in excessive estimates of needed resources with capacity value and fast ramping attributes.[137] Specifically, Sierra Club questions Idaho Power's use of a 15 percent planning reserve margin, in addition to regulating reserves to accommodate variable load and energy output.[138] However, Sierra Club does not indicate why this amount of reserves is excessive, nor does Sierra Club propose alternative amounts of planning or regulating reserves to ensure future reliability.

Sierra Club is correct that Idaho Power's IRP uses a 15 percent planning margin to account for load and resource variations, and an average (50th-percentile temperature-adjusted) load forecast. In the Company's previous IRPs, Idaho Power used a 5 percent

[135] STOP B2H Amended Opening Comments at 38.
[136] Idaho Power's Amended 2019 IRP at 52.
[137] Sierra Club's Opening Comments at 6-8.
[138] Sierra Club's Opening Comments at 7.

planning margin and a stressed, 1-in-20-year (95th percentile temperature-adjusted) load forecast during peak hours. As the Company explained, this decision to move to a 15 percent peak-hour planning margin based on a 50 h percentile temperature-adjusted load forecast is consistent with NERC's N-1 Reserve Margin criteria and is similar to the methodology employed by peer utilities for capacity planning.[139] To be clear, these methodologies do not yield significantly different results. While the percentage margin increases, the overall load to which that percentage is applied is lower. A comparison of the two methodologies is included in the Company's IRP.[140]

VII. DEMAND SIDE RESOURCES

Demand side resources ("DSM"), including energy efficiency and demand response, 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 energy efficiency and demand response programs available to all customer sectors and has achieved steady gains in DSM penetration over time. In addition to the Company's energy efficiency and demand response programs, Idaho Power conducts outreach and customer education programs to encourage its customers to make use of available programs and to use energy wisely.

A. Energy Efficiency

Both Staff and STOP B2H suggest that the Company is not doing enough to advance energy efficiency programs. STOP B2H argues that the Company should be expanding its energy efficiency offerings,[141] while Staff questions why the Company's preferred portfolio in this IRP provides for less energy efficiency than did the Company's 2017 IRP.[142] Staff notes that the 2019 preferred portfolio calls for 234 aMW of average annual load reduction and

[139] Idaho Power's Amended 2019 IRP at 97.
[140] Idaho Power's Amended 2019 IRP at 98 (Figure 8.1).
[141] STOP B2H's Amended Opening Comments at 44-52
[142] Staff's Opening Comments at 10-12.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

367 MW of peak reduction by 2038—a reduction from the 2017 IRP portfolio, which targeted 278 aMW of average annual load reduction and 483 MW of peak reduction by 2036.[143]

Staff's comments fail to recognize that the reduction in potential energy savings was driven by the anticipated advancement of the Energy Independence and Security Act ("EISA") lighting standards, which were to be fully adopted on January 1, 2020. These standards would have reduced the number of lighting measures available for inclusion in the Company's programs. As noted in the IRP,[144] although the amount of savings available for Idaho Power's programs would be reduced, customers in the Company's service area would have still benefited because the energy savings would reduce overall load without intervention from Idaho Power's programs. However, the EISA lighting standards were rolled back in late 2019 and did not take effect on January 1, 2020. This rollback will be reflected in Idaho Power's 2020 energy efficiency potential study.

Idaho Power's commitment to energy efficiency is evidenced by the significant gains Idaho Power has achieved in recent years thanks to its growing portfolio of energy efficiency programs. In the last few years, Idaho Power has increased its energy efficiency efforts in a number of ways, including providing low-income customers with coupons for no cost heating system tune-ups; expanding distribution of free energy efficiency kits, and initiating the Home Energy Report Pilot—a program designed to increase customer energy savings and which is expanding further in 2020.

Thanks in part to these expanding programs, in 2019, Idaho Power's energy efficiency program achieved record-level savings—the highest energy savings since the Idaho Energy Efficiency Rider began in 2002.[145] Energy savings in 2019 totaled 203,041 MWh, including

[143] Staff's Opening Comments at 10.
[144] Idaho Power's Amended 2019 IRP at 58
[145] Idaho Power's Demand-Side Management 2019 Annual Report at 1 (Mar. 15, 2020), *available at*: https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/2019DSM.pdf.

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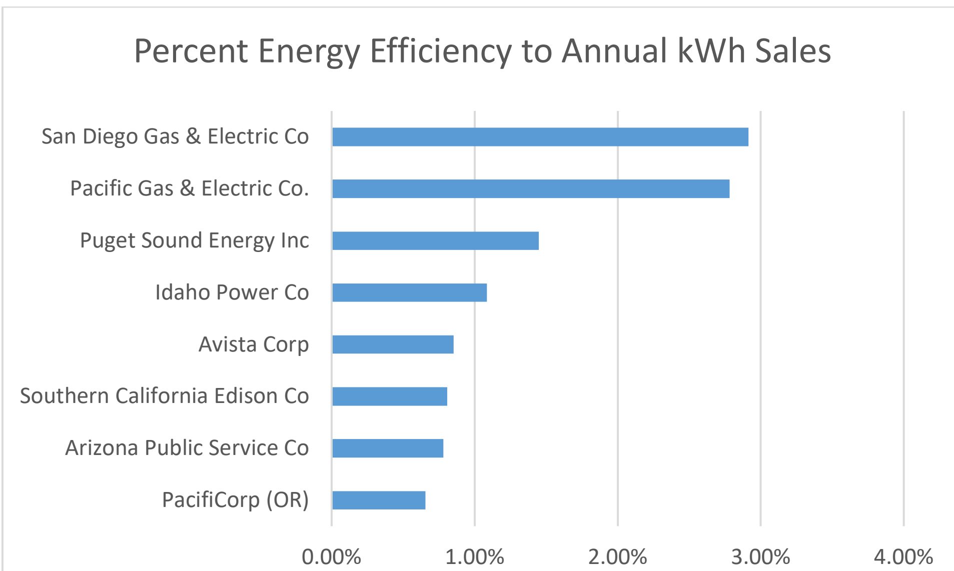
Portland, Oregon 97205

the estimated savings from the Northwest Energy Efficiency Alliance ("NEEA")—an increase of 18,963 MWh (or 10 percent) from 2018—and representing 1.4 percent of the Company's 2019 total kWh sales. Indeed, Idaho Power's energy efficiency programs alone, excluding the NEEA, saved 184,934 MWh in 2019—*a 17 percent increase from 2018*. In 2019, the company's energy efficiency portfolio was cost effective from both the total resource cost ("TRC") test and the utility cost test ("UCT") perspectives with ratios of 2.12 and 2.72, respectively. The portfolio was also cost-effective from the participant cost test ("PCT") ratio, which was 2.79. Idaho Power's ranking of energy efficiency savings (as a percentage of annual kWh sales) compared to other regional utilities is shown in Figure 4, below.[146]

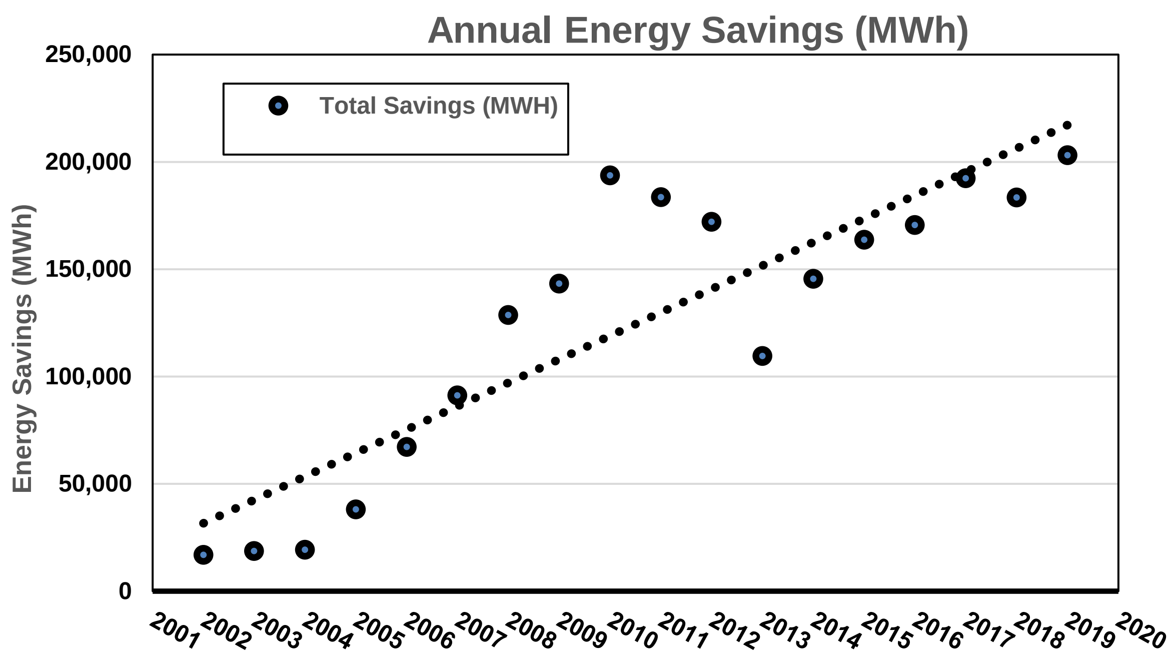
Figure 4: Percent of Energy Efficiency to Annual kWh Sales



Although there is high variability in annual energy efficiency savings—primarily due to changes in large commercial/industrial projects, which may take years to complete or may arise unexpectedly—the overall trend shows increasing energy efficiency savings. This overall increase in the Company's energy efficiency savings is depicted in Figure 5 below.

[146] Annual Electric Power Industry Report, Form EIA-861, 2018.

Figure 5: Annual Energy Savings (MWh)



Despite these increasing savings and the Company's considerable energy efficiency efforts, Staff questions whether Idaho Power has adequately reported on future expanded energy efficiency opportunities, as required by the Commission's order acknowledging the Company's 2017 IRP.[147] In addition to the discussion of energy efficiency provided in this IRP,[148] Idaho Power continues to work in consultation with the Energy Efficiency Advisory Group ("EEAG"), which includes members of Staff, to expand or modify the Company's energy efficiency portfolio. The Company continues to review new measures to determine cost-effectiveness and the practicality of adding to existing programs. Idaho Power is also engaged in ongoing efforts to identify efficiency measures through the Company's participation in the Northwest Energy Efficiency Alliance ("NEEA") Regional Emerging Technology Advisory Committee and the Regional Technical Forum ("RTF"). In 2019, Idaho Power also began

[147] Staff's Opening Comments at 10 (citing Order No. 18-176 at 16).
[148] Idaho Power's Amended 2019 IRP at 55-62.

subscribing to Energy Insights, which allows Idaho Power to view and search data from other North American utilities' Technical Reference Manuals ("TRMs") to obtain information on potential new energy efficiency measures and programs. Idaho Power representatives also attend national conferences and participate in webinars hosted by organizations interested in advancing energy efficiency savings. The Company reports any program changes in the annual DSM Report filed in both Idaho and Oregon (provided as Appendix B to the 2019 IRP).[149]

1. Valuing Transmission and Distribution Deferrals

Staff asks whether Idaho Power worked with other utilities in the region to explore updating how the Company values energy efficiency's role in deferring transmission and distribution investments, which the Company committed to do by the 2019 IRP.[150] Idaho Power worked extensively with the Northwest Power and Conservation Council ("NWPCC") as well as PacifiCorp and other utilities. This collaboration led to improvements in Idaho Power's approach to calculating how energy efficiency contributes to deferring transmission and distribution system investments. Major refinements included the following:

- Previously, only budgeted projects were considered in the analysis. For the updated analysis, the Company used a statistically significant sample from 17 years of historical projects as well as three years of budgeted projects for a total of 20 years of historical and budgeted projects. This increased the number of analyzed projects from 36 to 168.

[149] The Company's most recent DSM Report was issued on March 15, 2020. Idaho Power's Demand-Side Management 2019 Annual Report at 1 (Mar. 15, 2020), *available at*: https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/2019DSM.pdf.

[150] Staff's Opening Comments at 10 ("Idaho Power agreed to work with other utilities in the region to explore an update to the Company's methodology and values used for transmission and distribution system deferral values for its energy efficiency avoided costs by its next IRP.").

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Portland, Oregon 97205

- The previous analysis lumped all types of deferrals together. The updated analysis included separate categories for transmission, substation, and distribution deferrals.

The results of this new approach were used in the 2019 IRP.[151] These updated values are currently being used to calculate the cost-effectiveness of energy efficiency options.

2. Idaho Public Utility Commission Decision

Staff also asks how a recent, Idaho Public Utility Commission ("IPUC") decision concerning the means of selecting energy efficiency measures will impact the Company's cost savings forecasts. The IPUC directed Idaho Power to use the UCT—as opposed to the TRC test—as the primary measure to determine how much future cost-effective energy efficiency potential exists.[152] In 2019, Idaho Power retained a third-party consultant to conduct an energy efficiency potential study for use in the Company's 2021 IRP. This study will use the UCT as the primary screen for economically achievable energy efficiency potential, consistent with the IPUC's direction. The economic measure of achievable potential will be used for program planning, while the Company anticipates using the potential for technically achievable energy efficiency to create bundles of energy efficiency resources to include in the IRP portfolio modeling. While the UCT will serve as the primary screen, the energy efficiency study will also evaluate economic achievable potential using the TRC test, thus allowing the Company to compare the two approaches.

The Company initiated a discussion regarding the methodology for the potential study to be utilized in the 2021 IRP at an April 28, 2020, EEAG webinar where Oregon Commission Staff was in attendance. In that meeting, the Company's third-party consultant provided an overview of preliminary progress made in developing the potential study and the Company

[151] Idaho Power's Amended 2019 IRP at 61-62.
[152] Staff's Opening Comments at 12.

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

solicited input from the EEAG on inputs to the avoided costs used to determine cost-effectiveness. Idaho Power informed the EEAG that the Company intended to invite members from the IRPAC and the EEAG to participate in an additional meeting prior to the potential study being finalized to solicit additional input regarding how energy efficiency will be modeled in the 2021 IRP.

At this time, Idaho Power is uncertain how the IPUC's directive to use the UCT as the primary cost-effectiveness measure will affect the Company's programs or its analysis of the potential for new energy efficiency. The Company views 2020 as a transition year to allow for the Company's third-party consultant to complete the new energy efficiency potential study, and to then determine how the results will be used in load forecasting and in the 2021 IRP. Idaho Power conducts budgeting and planning in the fall of each year; next fall, the Company will plan 2021 energy efficiency activities based on the outcome of the new potential study.

3. Under-Forecasting

Staff points out that the Company's previous IRP targets for energy efficiency have been reliably exceeded by actual energy efficiency efforts.[153] Staff therefore suggests that the Company may be systematically under-forecasting energy efficiency potential, and asks the Company to consider "how to better improve its forecasting methodology" for energy efficiency "as it has [for] resource impacts."[154] Idaho Power believes that the new methodologies employed in the third-party potential study described above may determine an energy efficiency potential that more closely aligns with Idaho Power's historic accomplishments in energy savings.

4. Lessons Learned

Staff asks the Company to "clarify key learnings and future plans for energy efficiency

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[153] Staff's Opening Comments at 12.
[154] Staff's Opening Comments at 12.

selection modeling."[155] The 2019 IRP process was the first time the Company used the LTCE modeling feature within the AURORA model. This feature allowed the Company to model additional amounts of energy efficiency to compete as a potential new resource in the same manner as supply-side resource options. Like any new process, the Company identified opportunities for improvement and will incorporate lessons learned to develop a better process for the 2021 IRP. For instance, Idaho Power will revise the timing and completion of its energy efficiency potential study to more closely align with the start of the load forecast process. Additionally, the Company is exploring different methods of incorporating the energy efficiency potential into the load forecast and the 'bundling' of energy efficiency potential for IRP modeling. Moving forward, regardless of the model outcome, the Company will continue to pursue all cost-effective energy efficiency measures.

B. Demand Response

Idaho Power has been a leader in demand response since it began offering demand response programs in 2003. Idaho Power's 2019 demand response capacity was 397 MW, which equates to 12.2 and 11.6 percent of Idaho Power's 2019 peak demand and Idaho Power's all-time summer peak demand, respectively.

Demand response at Idaho Power is intended to be used for short-term capacity deficits in order to minimize or delay the need to build new supply side resources. Unlike energy efficiency programs or supply-side resources, demand response programs must acquire and retain participants each year to maintain a firm level of demand-reduction capacity for the Company. On a comparative basis, demand response as a resource is a very economic capacity resource and a very expensive energy resource. Idaho Power's demand response programs are available June 15 – August 15, which aligns with historic summer

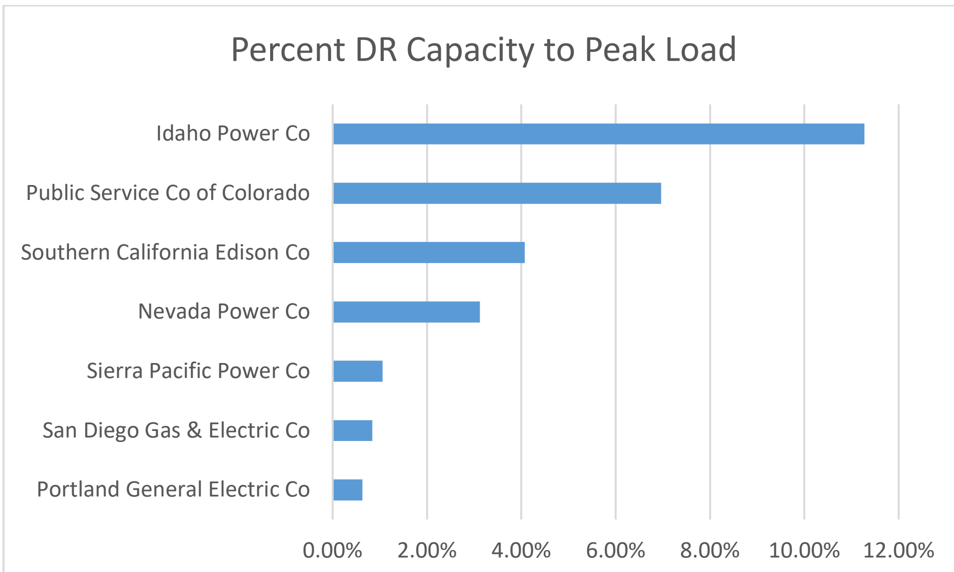
[155] Staff's Opening Comments at 12.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

peak loads, with the timing of capacity constraints in future years, and with the availability of irrigation and air conditioning loads.

Idaho Power's demand response capacity in 2018 (as a percentage of 2018 peak load) is shown in Figure 6, below, as compared to other regional utilities that report demand response capacity.[156]

Figure 6: Percent of Demand Response Capacity to Peak Load



1. <u>Timing of Demand Response Additions</u>

STOP B2H and CUB ask why the Company has delayed the use of demand response until 2031.[157] The 2019 IRP is not calling for additional DR capacity until 2031 primarily due to Idaho Power currently having 390 MW of demand response—nearly 12 percent of the Company's all-time system peak—as a resource to use for future summer capacity constraints. For background, in case IPC-E-12-29 at the IPUC, Idaho Power filed to suspend its two key demand response programs: A/C Cool Credit and Irrigation Peak Rewards

[156] Annual Electric Power Industry Report, Form EIA-861, 2018.
[157] STOP B2H's Amended Opening Comments at 44; CUB's Opening Comments at 4-5 ("While the original version of the IRP had 5MW of demand response (DR) resources in the preferred portfolio starting 2026, the amended version does not include any DR resource in the preferred portfolio until 2031.").

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Portland, Oregon 97205

programs. The Company's application arose from the results of its 2013 IRP, which identified no short-term capacity deficits in the load and resource balance analysis. Subsequently, as part of the public workshops in Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed to treat these existing programs as committed resources and agreed on a new methodology for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923 and OPUC Order No. 13-482, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours to be no more than $16.7 million. The agreement stemming from this case restricted Idaho Power's ability to expand its demand programs until the IRP shows a capacity need that could be satisfied by demand response. Idaho Power complies with these orders. Included in the settlement agreement was a directive to retain investments made in the three programs:[158]

Despite the fact that additions to the Company's demand response programs are not anticipated until 2031 in the preferred portfolio, the Company has maintained consistent demand response capacity since the 2013, as shown in Figure 7, below.

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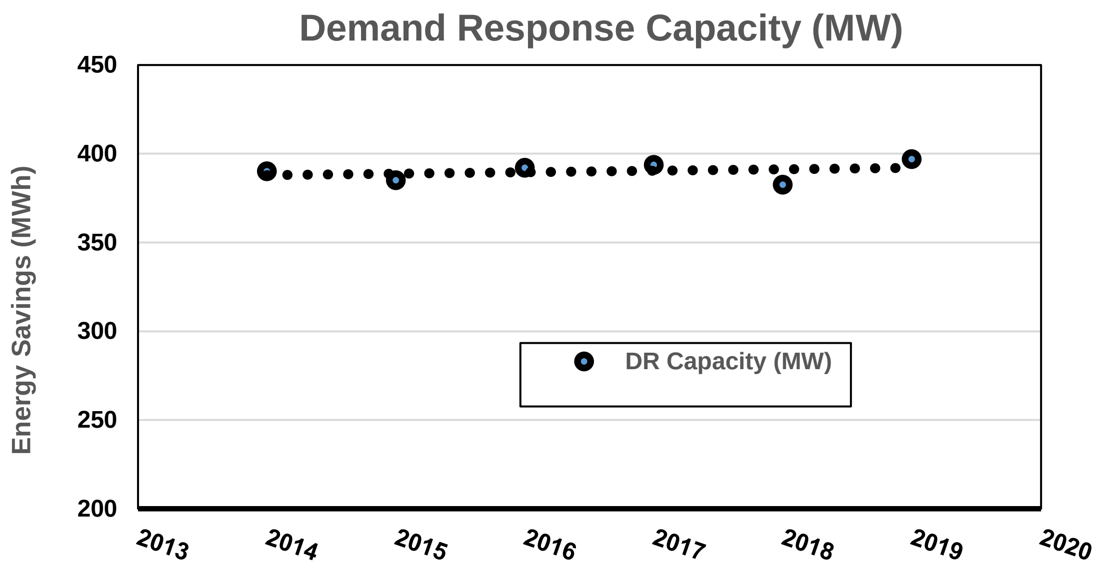
Figure 7: Demand Response Capacity (MW)



2. <u>Pilot Program</u>

In their opening comments CUB suggests that Idaho Power design pilot programs similar to PGE's in the near-term, which will bring more demand response resources into the Company's portfolio.[159] However, the IRP indicates that Idaho Power does not need any additional demand response until 2031 and shows no need for winter demand response. Therefore, it does not seem reasonable to invest in pilot programs many years ahead of the Company's identified need. Nonetheless, Idaho Power diligently stays informed on demand response programs, pilots, research, and equipment innovations through participation in the Demand Response Advisory Committee ("DRAC") as part of the Northwest Power and Conservation Council's 2021 Power Plan, as a founding member of the Pacific Northwest Demand Response Project ("PNDRP"), as a member of E-Source, and a member of the Peak Load Management Association ("PLMA"). Thus, Idaho Power will be fully prepared to pursue demand response investment when there is a near-term need.

[159] CUB's Opening Comments at 5.

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Portland, Oregon 97205

3. Capacity Cost

Both Staff and CUB object to how the Company estimated the capacity cost of demand response.[160] CUB and Staff note that the Company evaluates "committed demand response" at the levelized cost of capacity ("LCOC") of $29 per kW-year, while new incremental demand response is valued at $60 per kW-year in portfolio modeling. As CUB and Staff explain, the Company arrived at this $60 per kW-year by using approximately one-half the price of a Simple Cycle Combustion Turbine ("SCCT"), which has a capacity cost of $136 per kW-year.[161] Staff notes that, in the 2017 IRP Idaho Power's 2017 IRP, the LCOC for demand response was $5 per kW-month[162] or $60 per kW/year (escalated, $5.20 per kW-month or $62.42 per kW-year). Staff recommends rerunning the IRP model with different kW-year values for demand response (such as $32, $37, or $44 per kW-year).[163]

The Company disagrees that its capacity cost estimate is inappropriate or that reruns are necessary. As Staff notes, the 2017 IRP projected a similar LCOC for demand response of $62.42 per kW-year. Indeed, the 2017 IRP also showed the levelized cost of energy ("LCOE") for demand response to be $706 per MWh (escalated $734.52 per MWh)—the second most expensive energy resource.[164]

Demand response, as a customer-based program, is difficult to estimate with respect to future costs, particularly more than a decade into the future.[165] Moreover, as the Company explained in its response to Staff's data request, an expanded or new demand response program would entail additional equipment and set-up costs that are not included in recent cost figures.[166] For instance, the $29 per kW-year figure for 2018 does not include equipment

[160] CUB's Opening Comments at 6; Staff's Opening Comments at 14.
[161] Staff's Opening Comments (quoting Idaho Power's Response to Staff DR 41).
[162] Docket LC 68, Idaho Power's 2017 IRP at 87 (June 30, 2017).
[163] Staff's Opening Comments at 15.
[164] Docket LC 68, Idaho Power's 2017 IRP at 89.
[165] Staff's Opening Comments, Attach. A at 14 (Idaho Power's Response to Staff DR 41).
[166] Staff's Opening Comments, Attach. A at 14 (Idaho Power's Response to Staff DR 41).

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Portland, Oregon 97205

or set-up costs, as these were incurred in prior years.[167] Thus, the Company believes that its proxy value for demand response's capacity cost is reasonable.

4. Combined Demand Response and Solar

Staff suggests that future least-cost and least-risk analyses might involve pairing solar with demand response first, then pairing solar with batteries to achieve the benefits of battery storage.[168] Staff's proposal to pair demand response with solar might be feasible if the solar resource was sufficiently large and if the demand response resource's load shape matched the solar load shape. However, such an approach would be more costly and less flexible than a solar/battery combination. From a cost perspective, combined solar and demand response would likely result in a LCOC of $18.20 per kW-month (solar at $13 per kW-month and demand response at $5.20 per kW-month[169]), which is more expensive than the capacity costs of any of the solar/battery combinations analyzed in the Amended 2019 IRP.[170]

VIII. FORECASTS

A. Load Forecasts

Staff, STOP B2H, and Sierra Club comment on Idaho Power's long-term load forecast in the 2019 IRP, urging the Company to (1) remove data associated with certain time periods, (2) modify the Company's statistical modeling tools, (3) apply a simple linear projection rather than a more nuanced modeling approach, and (4) incorporate distributed energy resource contributions.[171] This analysis and feedback is described below.

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167 Idaho Power's 2019 Amended IRP at 61.
168 Staff's Opening Comments at 15.
169 LCOC of demand response from Idaho Power's 2017 IRP; the same metric was not calculated in the 2019 IRP.
170 Idaho Power's 2019 Amended IRP, App. C at 25.
171 In addition to the information included in the Company's 2019 IRP, the Company has worked with and submitted detailed load forecast modeling information to Staff for further review and analysis of its load forecasting process.

1. Idaho Power's Peak Load Growth Forecast Was Based on an Appropriate Time Period.

Sierra Club asserts that the Company should remove load data from the post-2008 economic recovery period from the peak load growth forecast, describing the Company's forecast as relying on "selective history[.]"[172] This proposal is both arbitrary and inconsistent with best practices in statistical modeling. By focusing exclusively on pre-2008 data, the Company would ignore relevant volatility and ongoing cycles at both economic and business levels. There is no basis for Sierra Club's assumption that removing the post-2008 growth results in a more representative snapshot than the Company's more comprehensive timeframe.

2. Idaho Power's Long-Term Load Forecasting Methodology Applied Appropriate Forecasting Tools.

Staff raises two potential issues in the Company's long-term load forecasting methodology, both of which concern specific modeling tools. First, Staff notes that the Company relies on ITRON's modeling, which is proprietary and therefore unavailable for more detailed inspection by the majority of interested parties. While Staff recognizes that ITRON is well-respected, accessing the underlying database is typically permitted only by visiting the Company's headquarters. In light of the current travel restrictions associated with COVID-19, traveling to view these materials on-site would be particularly difficult.

As the Company moved to utilizing ITRON's statistically adjusted end use ("SAE") framework for its residential sales and load forecast, engagement with the Company from the well-respected ITRON forecasting team and the U.S. Energy Information Administration ("EIA") has proved beneficial to increase the level of confidence in review and discussion of the results of the Company's residential forecast. The Company does not disagree that the level of detail that is quickly transferable in the residential forecast is limited. In response, the

[172] Sierra Club's Opening Comments at 7.

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Portland, Oregon 97205

Company has compiled a thorough review, in Excel format, of the assumptions, data, and determination of the XHEAT, XCOOL, and XOTHER variables used in the Company's ITRON residential SAE model.[173] Idaho Power hopes that its provision of this data resolves Staff's concern.

Second, Staff questions the Company's use of Ordinary Least Squares ("OLS") rather than time-series based regression models in the load analysis.[174] Staff suggests that the Company's forecasts could be improved by using the Auto Regressive Integrated Moving Average (ARIMA) models, which function very similarly to OLS but include three additional terms.

While Idaho Power appreciates Staff's input and potential model design suggestions, the Company is concerned that, while ARIMA models produce highly significant results for short-term forecasts, the long-term nature inherent in the integrated resource planning introduces a potential risk of inaccuracy and interpretability of moving averages throughout the forecast period without thorough testing. The Company will commit to using ARIMA error testing as an appropriate test for after-the-fact stationarity and will explore using other statistical methods for stationarity testing, recursive residual testing, etc., for the data that is currently utilized.

3. Long-Term Load Forecasting is a Complex Process.

STOP B2H argues that the Company's forecasting has created unnecessary confusion and suggests that a simple linear projection of Idaho Power's historical sales and load yields a more straightforward estimate.[175]

Load forecasting is a complicated endeavor. With the development and deployment

[173] This protected information was provided in the Excel spreadsheet accompanying Idaho Power's supplemental response to Staff's Request No. 20, filed on April 23, 2020.
[174] Staff's Opening Comments at 19.
[175] STOP B2H's Amended Opening Comments at 43.

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Portland, Oregon 97205

of an unprecedented number of new technologies, simple linear projections are useful as a basic measuring stick, but do not account for the increasingly complex network of energy consumption factors. As the Company's main goal is to ensure that its customers have safe and reliable electricity delivered to them now and in the future, load planning that leverages the most informed and reasonable forecasting methodologies is a prudent planning path. As such, with the advent of more modern statistical packages and computational power, more robust modeling architecture can be used to increase the accuracy of the Company's load forecasts. These tools enable the Company to test and measure end-uses, intensities, climatology, residuals, structural change, and serial correlation, among other factors.

In contrast, a simple linear trend analysis selects a specific start and end point to measure growth without considering exogenous factors. Such a simplistic extrapolation can be misleading. For instance, STOP B2H points to information showing that weather-adjusted sales growth between 2007 and 2018 was flat.[176] Yet using the same data that STOP B2H compiled, if the measurement period began only a few years later, the average annual growth in sales jumps back up to nearly 1 percent. Thus, assuming that a given time period is representative of future load growth may misrepresent actual future growth because it fails to account for the numerous other causes of increased or decreased load, such as business cycles, economic impacts, and new customer characteristics. Without this information, the forecasting models cannot account for inherent and highly relevant volatility.[177] In sum, the sales and load forecast and the methods used to derive the forecast in Idaho Power's 2019 IRP are reasonable and prudent.

[176] STOP B2H's Amended Opening Comments at 39.
[177] In addition, the Company's analysis also considered variations in the possible load futures as part of the risk and volatility analysis of the various portfolios.

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4. Idaho Power's Load Growth Forecast Incorporates Distributed Energy Resources.

STOP B2H also claims that Idaho Power's load forecast lacks any provision for future incorporation of distributed energy resources.[178] Contrary to STOP B2H's claim, Idaho Power does include a forecast of distributed energy resources in its load forecast.[179] Idaho Power's IRP discusses how Idaho Power incorporates energy efficiency, on-site generation, and electric vehicles in its load forecast.

B. Natural Gas Price Forecast

Staff asks the Company to explain in greater detail how its third-party vendor's natural gas forecast is reasonable.[180] Staff notes that the Company asserts that the third-party forecast was "compared" to Moody's Analytics and the New York Mercantile Exchange ("NYMEX") natural gas futures settlements, but did not explain how the Company weighed these data to determine the reasonableness of the third-party forecast.[181]

By way of background, Idaho Power used the EIA's High Oil and Gas Resource and Technology ("EIAHO") as the planning case natural gas forecast in the 2017 IRP—an approach that was highly criticized. As a result, the Company committed to continue evaluating the natural gas price forecast process and to work with stakeholders to develop an appropriate gas forecast for the 2019 IRP. Based on the methodologies employed by Idaho Power's peer utilities, and based on feedback from 2019 IRPAC meetings—which recommended that Idaho Power employ a third-party forecaster to eliminate any potential or perceived selection bias—Idaho Power enlisted the service of a well-known third-party vendor by subscribing to S&P Global Platt's North American Natural Gas Analytics

[178] STOP B2H's Amended Opening Comments at 43.
[179] Idaho Power's 2019 IRP, App. A at 33-34.
[180] Staff's Opening Comments at 17.
[181] Staff's Opening Comments at 17.

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Portland, Oregon 97205

("Platts").[182]

To verify the reasonableness of the Platts forecast, Idaho Power compared Platts' forecast to the EIA forecasts, and to Moody's Analytics and the NYMEX natural gas futures settlements. A comparison of these various natural gas price forecasts is depicted below, in Confidential Figure 8.

Figure 8: Confidential Comparison of Natural Gas Price Forecasts

[redacted]

As can be seen in the above graph, the EIA "high" and "reference" cases are both elevated, and do not reflect actual market prices. While the Moody's Analytics and Platts forecasts converge around 2029, the near-term Moody's Analytics forecast was far above where the market was trading at the time. Based on this comparative analysis, and given the robust natural gas forecasting methodology employed by Platts, the Company judged that Platts' natural gas forecast was reasonable.

[182] Idaho Power invited Beth McKay, Manager, North American Natural Gas Analytics at S&P Global Platts to present to the IRPAC on October 11, 2018.

C. PURPA Forecasts

REC has filed comments challenging Idaho Power's approach to forecasting power purchased from Qualifying Facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA)—and specifically, the IRP's assumptions as to which QFs will renew their expiring QF Energy Sales Agreements (ESA). In these comments, REC makes a variety of confusing arguments based on incorrect factual assertions and mischaracterizations of the Commission's relevant precedent. But fundamentally REC is arguing that the IRP should assume that all QFs with expiring ESAs will renew their contracts, and further that all renewing QFs should receive a capacity payment throughout the term of their ESAs. As discussed below, Idaho Power's IRP incorporates considered and informed assumptions about which QFs will renew their ESAs, and the question REC raises about whether renewing QFs should be paid for capacity throughout their contractual terms is a generic issue that should be addressed in UM 2000 or a related policy docket.

1. The IRP's Modeling of QF Contracts is Appropriate.

To be clear, Idaho Power has been consistent in the manner that it has included QFs in the 2019 IRP as it has in the Company's past IRPs. Idaho Power's Cogeneration and Small Power Production ("CSPP") forecast, which includes all QF projects under contract, is developed for each project based on a number of factors including: contract estimated generation amounts, most recent 12-month history, five-year rolling average, project adjusted estimated net energy amounts, and any previous or current adjustments. Generally, the starting point is the rolling five-year historical average of monthly generation, or shorter if the project has operated less than five years. If a project has operated less than one year, the generation estimates from the QF's ESA are used. Idaho Power uses the monthly adjusted net energy amounts supplied by QF's to verify information and make adjustments in its

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Portland, Oregon 97205

preparation of the CSPP forecast. These forecasts are generally updated on a quarterly basis, or more frequently if needed due to significant additions or subtractions of QFs in the forecast.

The 2019 IRP CSPP forecast was developed in the 3rd Quarter of 2018, and presented to the IRPAC on October 11, 2018. At that time, 134 QFs totaling approximately 1,149 MW were included. In its CSPP forecast, Idaho Power assumes all QF contracts, except for wind projects, will continue to deliver energy throughout the planning period, and the addition of replacement contracts will be consistent with PURPA rules and regulations existing at the time the replacement contracts are negotiated. Wind projects are not expected to enter replacement contracts. Currently, 627 MW of wind are under PURPA contract, and contract expirations begin in October 2025. By January 2033, the total wind under contract drops to 130 MW; by April 2037, the last of the current wind QF ESAs will have expired.

In Idaho Power's experience, PURPA contracts involving small hydro, biomass, cogeneration, and other renewable resource types have been replaced with new contracts with little or no additional investment required to maintain generation deliveries. By comparison, the cost of repowering wind QFs can be very significant, and therefore the Company cannot as accurately predict whether these generators will choose to repower. Idaho Power understands that repowering wind turbines is being actively examined and pursued in the wind industry, but is not yet clear when or how this approach will be adopted for particular projects, and in particular for wind QF projects. And given the amount of wind that Idaho Power currently has on its system, it would be unwise for Idaho Power to simply assume, without a sound basis, that all of that capacity will be available in perpetuity. Idaho Power continues to monitor developments in wind repowering and may choose to adjust future planning processes accordingly.

REC argues that the Commission should "act now in the IRP to correct Idaho Power's assumptions and inputs around QF renewals," but its arguments suggest that it does not

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understand how QF renewals are modeled in the IRP. Idaho Power hopes that that these comments clarify the matter for REC and looks forward to answering any additional questions about its approach through further process in this docket.

2. Questions About Whether Renewing QFs Should Receive Capacity Payments Regardless of a Utility's Resource Sufficiency Should be Considered in a Generic Proceeding.

In addition to questioning Idaho Power's modeling assumptions for QF contracts, REC argues that QFs renewing their ESAs are entitled to a capacity payment regardless of the utility's resource sufficiency, and argues that this docket is the appropriate venue to address this issue. However, REC is mistaken that this issue has been previously resolved by the Commission, as in fact such a proposal would require a significant modification to the utilities' avoided cost prices. Moreover, REC's argument is a generic issue appropriately raised in a generic proceeding such as Docket UM 2000, in which the Commission will be considering changes to its current avoided cost policies.

First, contrary to REC's claims, this Commission has never determined that renewing QFs should be compensated for capacity during the utility's sufficiency period, and Idaho Power certainly is not in violation of any Commission orders with respect to its avoided cost prices. REC's argument that that Idaho Power is in violation of Commission orders is based entirely on its reading of the Commission's Order No. 14-058 in Docket UM 1610 and Order No. 18-138 in Docket LC 67. Unfortunately, REC has mischaracterized those orders and their implications for Idaho Power.

In UM 1610, REC asked the Commission to consider whether QFs should be paid for capacity during a utility's sufficiency period at a price other than market price. On this point, REC explains that its stated concern in that case was that PacifiCorp's IRP assumed that the QFs would all renew their contracts, but that PacifiCorp did not provide a capacity payment to these same QFs when they did renew. REC quotes the Commission Order on this issue for the proposition that the "QFs were 'effectively providing [capacity to PacifiCorp] for free'"[183] and notes that the Commission asked PacifiCorp to work with the QFs in its next IRP on this issue. However, contrary to REC's implication, the sentiment that QFs were providing capacity for "free" was not the Commission's view—the quoted language was taken from the portion of the Commission's order where it was recounting REC's position, and in no way reflects the Commission's perspective. And while the Commission directed PacifiCorp to work with the parties on this issue in its next IRP, the Commission clearly did not direct the utilities in general or Idaho Power specifically to take any specific action on this point.

REC again materially mischaracterizes the Commission's actions in in its discussion of Order No. 16-071 in Docket LC 62, a PacifiCorp IRP proceeding, in which PacifiCorp's modeling assumed that no QFs renew their contracts. REC quotes the Commission as stating that "'non-renewal may not be the best planning assumption when many (or most) QFs do, in fact, renew.'" In doing so, REC has edited out half of the relevant sentence. The Commission's actual conclusion was as follows: "We acknowledge that non-renewal may not be the best planning assumption when many (or most) QFs do, in fact, renew, ***but question the value of additional studies of the capacity of renewing QFs***."[184] Thus, contrary to REC's implications, there is no support whatsoever to REC's claim that Idaho Power's modeling assumptions, or its avoided cost prices, are in violation of Commission direction.

Second, and most importantly, the issue that REC is raising does not really concern the accuracy of Idaho Power's IRP modeling methodology, but rather the methodology by which avoided costs are calculated for renewing QFs. Moreover, as evidenced by REC's comments, it is clear that REC's issue is not specific to Idaho Power but is applicable to the avoided cost methodology of all utilities. As such, this issue should be addressed in UM 2000

[183] Renewable Energy Coalition's Opening Comments at 5 (quoting Order No. 14-058) (Apr. 2, 2020).
[184] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket LC 67, Order No. 18-138 at 12 (emphasis added) (Apr. 27, 2018).

or a related proceeding, in which the Commission intends to consider changes to avoided cost modeling.

Indeed, a recent Staff Agenda from Docket UM 2011 (a general capacity investigation) indicates that the Commission is in the process of considering changes to how capacity values are determined, including their relationship to a utility's sufficiency/deficiency periods.[185] To the extent that REC believes that its capacity value is being underrepresented, such a question should be presented in the course of a generic, policy-based investigation.

3. <u>REC's Argument that Idaho Power is at Fault for Considering Only Signed Contracts is Without Merit.</u>

REC also makes a very confusing argument that Idaho Power is specifically at fault in its 2015 and 2019 IRPs for accounting only for "signed contracts" in its IRP.[186] It is unclear whether REC is arguing that Idaho Power should include all QFs that have made inquiries regarding ESAs in its IRP planning—regardless of whether they have signed contracts—or if REC is referring only to renewing QFs, and is under the impression that Idaho Power does not assume that QFs with current ESAs will renew.

If REC believes that all QFs should be included in IRP modeling prior to signing a PPA—that view is without merit. Idaho Power cannot include QF generation in its planning processes without having a signed contract, because a QF would have no reason to deliver generation to the utility nor would the utility have any reason to pay for QF generation without a contract. As a practical matter, a significant percentage of QFs seeking ESAs will never actually sign an ESA. Thus, including all QFs seeking ESAs in IRP modeling would overstate the amount of capacity that Idaho Power can expect.

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[185] *In the Matter of Pub. Util. Comm'n of Oregon, General Capacity Investigation*, Docket UM 2011, Staff Agenda at 3 (Oct. 15, 2019).
[186] While REC specifically points out the 2015 and 2019 IRPs, the Company's methodology was the same in the 2017 IRP.

McDowell Rackner Gibson PC
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Portland, Oregon 97205

If REC's argument refers only to renewing QFs, and suggests that Idaho Power does not assume that such QFs will renew, that view is incorrect. Idaho Power assumes that all QFs with signed contracts will seek a new replacement contract when an existing contract expires and generation from the QFs is continued in the CSPP forecast, with the exception of wind.

IX. OTHER

A. Gateway West

Staff questions how seriously the Gateway West transmission project is being considered by both Idaho Power and PacifiCorp as a least-cost/least-risk resource.[187] Staff points out that Idaho Power did not include Gateway West in the action plan in its 2019 IRP even though it was an action item in the 2017 IRP, and notes that the Commission had previously directed Idaho Power to update the Commission on an ongoing basis concerning Energy Gateway's progress.[188] Staff also states that neither Idaho Power nor PacifiCorp have included Gateway West in the preferred portfolios for each company's most recent IRP.[189]

Idaho Power provides quarterly update reports to the Commission on B2H and Gateway West. The first quarter 2020 report was filed on April 27, 2020.[190] Idaho Power did not include Gateway West in its action plan because it is not, as of yet, a viable replacement for Idaho Power's supply-side resources. While the anticipated benefits of Gateway West are significant, unlike the B2H project Gateway West will not provide direct access to a liquid market. Nonetheless, the project will provide other long-term benefits such as relieving transmission constraints, providing greater options for future generation resources, and helping to meet future transmission needs, such as those associated with integrating

[187] Staff's Opening Comments at 23.
[188] Staff's Opening Comments at 23.
[189] Staff's Opening Comments at 23.
[190] Idaho Power Company's 1st Quarter 2020 Transmission Update (Apr. 27, 2020).

intermittent resources.

B. Climate Change and Clean Energy Goals

Parties raise a number of questions regarding how the Company's IRP accounted for climate change and clean energy goals. While parties express support for Idaho Power's goal of achieving 100 percent clean energy by 2045, parties also raise concerns regarding (1) the Company's hydro modeling, (2) the Company's Climate Change Plan Report, and (3) the implications of the Company's clean energy goal .

1. Hydro Modeling

Staff asks the Company to explain what changes in hydrologic analysis have been made since the last IRP. Staff has ongoing concerns regarding the Company's hydro analysis and correlation with peak loads, noting that the Company has performed its capacity deficit analysis the same way since the early 2000's and that Staff had previously recommended that the Company take a fresh look at the conservative peak hour assumptions in the 2019 IRP.[191] However, Staff indicates that Idaho Power appears not to have addressed Staff's concerns, and thus asks the Company to explain "whether there are any notable changes to capacity factors and other assumptions from the last IRP."[192]

To clarify, the Company's 2019 IRP did not use hydro analysis and correlation with peak loads in the same manner as in previous IRPs. Previously, Idaho Power had used hydro analysis (specifically, 90th percentile streamflow conditions) and correlation with peak load (specifically, 95th percentile peak-hour load) to make a capacity deficit determination, which was then used to determine when new resources needed to be added to the Company's system. In the 2019 IRP, the Company did not develop an independent capacity deficit determination, and instead relied on the LTCE capability of the AURORA model to develop

[191] Staff's Opening Comments at 21.
[192] Staff's Opening Comments at 21.

McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

resource portfolios, based on a 50th percentile load forecast with a 15 percent peak-hour planning margin.[193] The LTCE tool in the AURORA model was able to economically add or retire resources without a defined capacity deficit. Nonetheless, the Company did use hydro condition and peak load forecasts to develop the peak-hour planning margin parameter for the AURORA model. Thus, the Company addresses both the hydrologic analysis and the peak load forecasting in turn.

With respect to the Company's hydrologic analysis, the models used to develop the hydro forecast for the 2019 IRP remained unchanged from the 2017 IRP, as the Company believes that the 90 percent exceedance remains appropriate based on observed inflows. The Company evaluates resource sufficiency for the future peak-hour based on low water conditions—*i.e.*, the modeled 90 percent exceedance. In evaluating how the modeled 90 percent exceedance hydro condition compares to historical (1981-2018) conditions, the Company considers two time periods for comparison: September – March and April – August.

For instance, during the September – March period, the modeled inflow into Brownlee Reservoir is within 10 percent of the historical 90 percent exceedance flow and is a mix of slightly higher and slightly lower than the historical observed Brownlee Reservoir inflow. However, during the April – August time period, the modeled 90 percent exceedance is approximately 10-15 percent higher than the observed 90 percent exceedance inflow. This increase in modeled water supply reflects future basin conditions, including aquifer management and weather modification.

Although the Company has selected to use the modeled 90 percent exceedance hydrologic condition to evaluate resource sufficiency for the future peak-hour, the 90 percent exceedance was evaluated against the 100 percent and 70 percent exceedance. The table below demonstrates the sensitivity of the modeled Brownlee Reservoir inflow for year 2038

[193] Idaho Power's Amended 2019 IRP at 97.

given the 100 percent, 90 percent, and 70 percent exceedance.[194]

Table 6: Comparison of Exceedances for Inflow to Brownlee

Comparison of the 100, 90 and 70 Percent Exceedances for Inflow to Brownlee the 2019 IRP WY 2038

Flow	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
100% 2019 IRP - WY2019	9506	9558	10943	10299	9466	7184	6715	6940	7795	8933	9744	9028
90% 2019 IRP - WY2019	10243	10849	12632	13913	15567	10912	8341	8570	8947	10186	10409	10144
70% 2020 IRP - WY2019	12448	14349	14778	18982	21745	17340	9135	9078	9874	11067	11144	11651

Idaho Power continues to track the latest climate projections, as well as studies that are being conducted to reflect relevant temperature, precipitation, and streamflow changes in the Snake River Basin. As mentioned in the IRP, Idaho Power's hydropower system is situated downstream from federally managed irrigation and hydropower projects on the Snake, Boise, Payette, Owyhee, and other tributaries.[195] Due to the position of Idaho Power's hydropower facilities, any changes to federal project operations as a result of climate change will impact Idaho Power's hydropower system. Rather than create a separate climate change impact study for the Company's hydropower system, Idaho Power has relied heavily on the River Management and Joint Operating Committee ("RMJOC"), Second Edition, Part 1 report ("RMJOC-II Part 1"), prepared for the RMJOC members.[196] The RMJOC-II Part 1 report focuses on the potential changes to temperature, precipitation, snowpack, and natural streamflow in the Columbia and Willamette River Basins under a variety of future climate scenarios and with multiple methods for responding to hydrological changes. Subsequent studies that are not yet available will use the RMJOC-II Part 1 results to evaluate climate change risks and uncertainties relevant to the federal hydropower system.

[194] Additional analysis of historical and modeled Brownlee Reservoir inflows can be found in the Company's IRP. Idaho Power's Amended 2019 IRP at 84.
[195] Idaho Power's Amended 2019 IRP at 19.
[196] The RMJOC members include BPA, the US Army Corps of Engineers, and the US Bureau of Reclamation.

Going forward, Idaho Power plans to continue utilizing RMJOC-II regulation modeling studies and findings as they become available. This maintains a consistent framework for understanding the risks and uncertainties associated with climate change impacts to hydropower throughout the Snake River Basin and allows Idaho Power's projections to be informed by findings for the upstream federal system.

For the 2019 IRP, upstream reservoir regulation is not yet available from RMJOC-II, so Idaho Power conducted its own internal climate risk analysis and has summarized the key findings based on preliminary modeling using the available RMJOC-II Part I natural streamflow datasets. The modeling for future IRP cycles will be expanded and updated as future Federal Columbia River Hydropower reports and datasets become available.

With respect to Staff's concerns regarding the Company's peak load forecasting, the Company believes that it appropriately forecasts peak-hour demand as an integral part of the Company's system planning. Peak-hour demands are forecast using a system of 12 regression equations, one for each month of the year. For most monthly models, the regressions are estimated using 25 years of historical data; however, the estimation periods vary. The peak-hour forecasting regressions express system peak-hour demands, and are primarily a function of monthly sales (stated in average megawatts) and average peak-day temperatures, as well as real electricity prices and (in some months) precipitation. The Company's three special contract customers' contribution to peak is determined separately using historical coincident peak factors, which is then added to determine the overall system peak.

The forecast of average peak-day temperatures is a key driver of the monthly system peak models. The normal average peak-day temperature drivers are calculated over the most recent 30-year period to capture recent climatological updates. In addition, the peak model develops peak-scenarios based on historical probabilities of peak day temperatures at the

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Portland, Oregon 97205

50th, 90th, and 95th percentiles of occurrence for each month of the year. However, the system peak regression models for the summer months (June, July, and August) were re-specified to reflect an increasing temperature trend during those months. These weighted average peak-day temperatures are added to the regression models to help determine the peak hour. In sample testing, adding the weighted average peak-day temperatures more accurately reflected actual historical summertime system peaks.

2. Idaho Power's Climate Change Plan Report

Staff asks the Company to explain how it complied with the Commission's directive to develop a report assessing the risk and uncertainties associated with climate change to Idaho Power and its customers.[197] While Idaho Power has examined the effects of climate change on its hydropower system in the 2019 IRP,[198] the Company is in the process of developing a more comprehensive internal plan and provides an update on these efforts below.

On an annual basis, Idaho Power publishes a Sustainability Report providing details on the Company's recent efforts to strengthen its sustainable foundation. The 2018 Sustainability Report is available on Idaho Power's website,[199] while the 2019 Sustainability Report will be published on May 21, 2020. A highlight in the 2019 report is an update on Idaho Power's Climate Change Adaptation Plan ("Adaptation Plan"), which will address fish habitat restoration, changing hydroelectric operations, increased electricity demand, wildfire prevention, and vegetation management.

A key focus of the Company's Adaptation Plan concerns wildfires. Fires can cause a wide range of direct and indirect harms, from community damage to air quality and wildlife degradation, reduced recreation access, and power outages—along with the associated

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[197] Staff's Opening Comments at 21.
[198] Idaho Power's Amended 2019 IRP at 85.
[199] 2018 Sustainability Report, *available at*: https://docs.idahopower.com/pdfs/AboutUs/sustainabilityReport/Sustainability_Report_2018.pdf

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Portland, Oregon 97205

harms associated with lack of energy services. Idaho Power's attention to safety and reliability starts with the quality of its equipment, such as power lines, poles, substations and transformers. The Company designs and builds its equipment to meet or exceed industry standards, monitors the ongoing equipment condition, and works hard to maintain the Company's infrastructure in suitable working order.

With these goals in mind, Idaho Power operates a robust vegetation management program to keep trees and other plants away from its lines. This work includes pruning and, if necessary, removing trees. A sterilant is applied around select power poles to keep plants from growing nearby. These actions have proved successful in saving poles and lines during summertime wildfire events in Idaho.

3. Idaho Power's Clean Energy Goal

Staff, Sierra Club, and Renewable Northwest comment on Idaho Power's goal of 100 percent clean energy by 2045. While these comments generally support the Company's commitment to reduce carbon emissions, they also recommend changes to future IRPs to ensure that the Company can meet its clean energy goal while also protecting ratepayers.[200]

The Company agrees that future IRPs will need to fully reflect the Company's clean energy goal. However, Idaho Power announced this goal in March of 2019, midway through the 2019 IRP preparation process. Given that the Company prepares an IRP every two years, the Company will continue to advance its clean energy goal in future IRPs.

Staff questions how the natural gas additions in 2030 and 2035 in the Company's preferred portfolio align with the Company's clean energy goal, without resulting in significant

[200] Staff's Opening Comments at 22 ("While it is too late to incorporate this goal into the current IRP, Staff believes it is appropriate to raise the question of how such an aggressive goal will impact Idaho Power ratepayers."); Sierra Club's Opening Comments at 6 ("[F]uture IRPs must evaluate portfolio designs to meet the 2045 goal[.]") (emphasis omitted); Renewable Northwest's Opening Comments at 5-6.

stranded assets.[201] As noted above, the natural gas generation identified in the preferred portfolio is intended as a placeholder for flexible resources that can meet system needs. Because the Company views the future natural gas resources as surrogates for resource attributes, the Company felt it was not appropriate to make assumptions about early-retirement of natural gas resources in the portfolio costs. Technologies are evolving and flexible resources will be evaluated at the time they are needed.

Flexible generation formed a significant part of the Company's Amended 2019 IRP, ranging from 1,103 MW to 300 MW depending on the portfolio. The preferred portfolio contains 411 MW of flexible resource additions. The Company will continue to evaluate resource technologies and costs as it models its transition to 100 percent clean energy. Moreover, prior to any specific natural gas addition, Idaho Power would anticipate issuing an RFP closer to when the resource is needed.

Lastly, Sierra Club states that the Company needs to update its CO_2 goals to align with the goal to achieve 100 percent clean energy by 2045.[202] While Idaho Power is currently meeting and exceeding the existing corporate CO_2 goal,[203] presently the Company is looking at revising these goals to reflect the Company's broader 100 percent clean energy goal.

C. Jackpot Solar

Both Staff[204] and CUB[205] recommend that the Company's action item related to Jackpot Solar PPA approval not be acknowledged in this IRP as the decision has already been made and the contract has been executed.

Idaho Power's action plan in its amended IRP included two action items that were

[201] Staff's Opening Comments at 18.
[202] Sierra Club's Opening Comments at 6.
[203] Idaho Power's Amended 2019 IRP at 11.
[204] Staff's Opening Comments at 25.
[205] CUB's Opening Comments at 2-4.

noted with an asterisk (*) as "complete at the time the Amended IRP was filed,"[206] one being the "Jackpot Solar PPA regulatory approval – on-line December 2022." The Company included this action item in its Amended IRP action plan as it was a significant decision that was based on the results of the 2019 IRP analysis and was part of the action plan in the originally filed IRP. It is important to note that the Jackpot Solar project approached Idaho Power at a unique time where the Company was able to analyze the proposed PPA within the 2019 IRP portfolio development and analysis. The PPA was included in the New Resources table and, using the LTCE capability of AURORA, the model was able to select the Jackpot Solar PPA (or not) as a cost-effective resource rather than a resource based on capacity or energy need. As shown in the LTCE results in the 2019 Amended IRP – Appendix C, the Jackpot Solar PPA was selected in the majority of the 24 WECC-optimized portfolios.

Because Idaho Power had to make a timebound decision on the PPA, Idaho Power agrees that the action item related to Jackpot Solar PPA regulatory approval should be removed and the Company will request prudency and recovery of the PPA in a future ratemaking docket.

D. 2020 Variable Energy Resources Study

Staff[207] and Renewable Northwest[208] provide brief comments on Idaho Power's action plan item to conduct a new variable energy resources ("VER") study in 2020 and support the Company's action item. The Company's 2018 VER study concluded that Idaho Power's system was nearing a point at which the current configuration can no longer integrate additional VERs.[209] Idaho Power takes this opportunity to provide an update on the progress

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[206] Idaho Power's Amended 2019 IRP at 15.
[207] Staff's Opening Comments at 22.
[208] Renewable Northwest's Opening Comments at 6.
[209] *In the Matter of Idaho Power Co., Application for Approval of Solar Integration Charge*, Docket UM 1793, Idaho Power's 2018 Variable Energy Resource Integration Analysis Compliance Filing at 10 (July 31, 2018).

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419 SW 11th Avenue, Suite 400
Portland, Oregon 97205

of the Company's VER study action item.

Similar to the 2018 VER study, Idaho Power has convened a Technical Review Committee consisting of subject matter experts within Idaho Power and external stakeholders from both the Commission and the IPUC, including Staff, Northwest Power and Conservation Council, the University of Idaho, Idaho National Lab ("INL"), and the National Renewable Energy Laboratory ("NREL"). Given the near-term VER limits and to ensure a comprehensive and robust analysis, Idaho Power issued an RFP for a consultant to assist on the project. Based on the RFP responses, the Company selected E3 Consulting to assist the Company and the Technical Review Committee with the 2020 VER study. The 2020 VER study will provide critical information on the level of VERs that Idaho Power's system can integrate before additional flexible resources are required. Additionally, the study will update integration charges and rules for VERs that will be used in the modeling for the 2021 IRP. The 2020 VER study is expected to be completed and available publicly in September of 2020. The Company is currently working with the Technical Review Committee and E3 on the study.

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 15th day of May, 2020.

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the confidential pages of Idaho Power Company's Reply Comments in Docket LC 74 on the parties listed below via e-mail in compliance with OAR 860-001-0180.

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