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August 16, 2022

VIA ELECTRONIC FILING

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

Re: Docket LC 78 - In the Matter of Idaho Power Company's 2021 Integrated Resource Plan ("IRP").

Attention Filing Center:

Attached for filing is an Errata to Idaho Power Company's Reply Comments filed August 4, 2022. This filing reclassifies information on page 10 previously believed to be highly confidential as confidential information. This errata also removes footnote 21 which explained why the information was designated as highly confidential. Attachment 1 remains highly confidential.[1]

This revised version of Reply Comments should fully replace the version filed on August 4, 2022. Confidential copies will be provided via encrypted PDF file to the Filing Center and parties that have signed General Protective Order No. 22-212. Please contact this office with any questions.

Sincerely,

Lisa Rackner

Lisa Rackner

Attachment

[1] Idaho Power is still awaiting an Order granting its Motion for Modified Protective Order.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 78

In the Matter of: IDAHO POWER COMPANY'S 2021 Integrated Resource Plan.	**ERRATA TO IDAHO POWER COMPANY'S REPLY COMMENTS**

Originally Filed: August 4, 2022

Errata Filed: August 16, 2022

REDACTED

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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 Renewable Energy Coalition ("REC"), the Oregon Citizens' Utility Board ("CUB"), Renewable Northwest, and the STOP B2H Coalition ("STOP B2H").

Idaho Power requests that the Commission acknowledge the Company's 2021 Integrated Resource Plan ("IRP"), as submitted to the Commission on December 30, 2021. The IRP satisfies each of the Commission's procedural and substantive requirements. The Company's Short-Term Action Plan ("Action Plan") and preferred long-term resource portfolio ("Preferred Portfolio") are supported by robust and comprehensive analysis demonstrating the reasonableness of the plan.[1]

The 2021 IRP is a comprehensive analysis of the optimal mix of both demand- and supply-side resources needed to meet flexible capacity needs and reliably serve customer demand over the 20-year planning horizon from 2021 to 2040. As a result of meaningful feedback from Commission Staff and stakeholders, the 2021 IRP reflects significant improvements over past IRPs to scenario modeling and other planning analyses, as well as enhanced process controls. For instance, in response to Commission Order No. 16-326 and Staff's concerns regarding the Company's prior methods in determining the capacity contribution of variable energy resources ("VERs"), the 2021 IRP has transitioned to the full effective load carrying capability ("ELCC") method—a more accurate methodology in determining capacity contribution for such resources. Additionally, a major improvement in scenario modeling was achieved by leveraging AURORA's refined long-term capacity expansion ("LTCE") model to co-optimize for Idaho Power and the broader West. Finally, the Company completed significant validation and verification of the modeling, enhanced its reliability analysis, and conducted risk and scenario analyses to ensure

[1] *In re Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002, App'x at 1-3 (Jan. 8, 2007).

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the proper selection of the Preferred Portfolio. Accordingly, the 2021 IRP represents a significant improvement in the accuracy and reliability of Idaho Power's analyses and forecasts.

The 2021 IRP Preferred Portfolio successfully positions Idaho Power to provide reliable, economic, and environmentally sound service to its customers into the future. The 2021-2027 Action Plan associated with the Preferred Portfolio includes the following core resource actions: (1) conversion of Bridger Units 1 and 2 from coal to natural gas by summer 2024 with a 2034 plant exit date; (2) acquisition of significant capacity and energy resources to meet demand growth needs in 2023 through 2027, including 120 megawatts ("MW") of added solar PV capacity by 2023; (3) exit from both Bridger Unit 3 and Valmy Unit 2 by year-end 2025; and (4) completion of the Boardman-to-Hemingway transmission line ("B2H") by 2026.[2]

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's preferred resource portfolio, the B2H project has served as a critical component of Idaho Power's preferred portfolios since the 2009 IRP and has consistently represented the least-cost, least-risk resource for customers. In the last six IRPs, the Commission has recognized that continued development of the project is reasonable. These resource actions are largely supported by the parties to this proceeding, with the exception of STOP B2H'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 set out and addressed in turn.

[2] Idaho Power's 2021 IRP at 166 (Dec. 30, 2021) [hereinafter, "2021 IRP"].

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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.[3] The primary goal of an IRP is to select the least cost/risk portfolio for the utility and customers.[4] To meet this goal, the Commission requires the IRP to analyze a planning horizon of "at least 20 years."[5] While the fundamental goal of the IRP is the identification of the Preferred Portfolio, the Commission's guidelines also require the IRP to include an action plan that identifies the specific resource activities the utility intends to undertake in the next two to four years.[6] When adopting the IRP guidelines, the Commission noted that, "in an IRP, the Commission looks at the reasonableness of individual actions in the context of the entire plan."[7]

When acknowledging an IRP, the Commission acknowledges only the action plan and does not acknowledge action items planned to occur more than four years in the future.[8] Commission acknowledgment confirms that the action plan satisfies the procedural and substantive requirements of the Commission's IRP guidelines and is "reasonable based on the information available at that time."[9]

Importantly, the Commission has repeatedly "reaffirm[ed] [its] long-standing view that decisions made in IRP proceedings do not constitute ratemaking."[10] Further, "[d]ecisions whether

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[3] *In re Idaho Power Company, 2013 Integrated Resource Plan*, Docket No. LC 58, Order No. 14-253 at 1 (July 8, 2014).
[4] 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.").
[5] Order No. 07-002 at 5.
[6] Order No. 07-002 at 12 (Guideline 4(n)).
[7] Order No. 07-002 at 25.
[8] Order No. 14-253 at 12; *In re Idaho Power Company, 2011 Integrated Resource Plan*, Docket No. LC 53, Order No. 12-177 at 6 (May 21, 2012) ("We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items . . .").
[9] Order No. 14-253 at 1.
[10] Order No. 14-253 at 1.

to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding."[11]

III. STAFF'S COMMENTS

Staff's Opening Comments do not make specific recommendations for Commission action regarding the 2021 IRP or the various topics of interest. Rather, Staff identifies areas for which they believe additional information and analysis is required before a final recommendation can be made in this docket. Staff's Opening Comments focus on load forecasting, demand response ("DR"), IRP modeling, transmission, modeling investment costs, and climate change and greenhouse gas ("GHG") emissions. The Company appreciates Staff's review thus far and, in reply, provides responses to Staff's one recommendation and thirty-seven (37) requests for additional information.

A. Load Forecasting

Staff's Opening Comments point out that load growth is a significant driver of the Company's immediate capacity deficit and need for near-term investments, and notes concerns around the limited historical data informing the residential sector and the accuracy of the projected growth in the commercial and industrial sectors within the system load forecast. Additionally, Staff believes the Company's 2021 IRP and responses to Staff's data requests were insufficient to independently reproduce the Company's 2021 IRP's published results and requests the Company provide additional information.

1. Load Forecast - Growth Rate Assumption

The Company projects overall system load to grow at an annual rate of 1.4 percent from 2021 to 2040, representing a 40 percent increase from the last IRP. Staff believes that the anticipated growth in energy sales may be overestimating growth in the planning period, especially in the near term, and inquires if Idaho Power's load forecast represents the upper

[11] Order No. 14-253 at 1.

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bound from a range of scenarios.[12] Staff's Request for Company Reply Comments 1 requests that the Company describe where its load forecast belongs within a range of load forecast assumptions.[13]

The planning case load forecast discussed by Staff is based on the 2021 economic forecast vintage for the Company's service area, representing the highest probability outcome for load growth during the planning period, or the 50th percentile given historic growth rates.

To account for economic uncertainty, two additional load forecasts were prepared for Idaho Power's service area based on the planning case load forecast. The forecasts provided a range of possible load growth rates for the 2021 to 2040 planning period for high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the previous 25 years (1996–2020).

Three observations can be made for the three scenarios: 1) the expected-case forecast is the median growth path; 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario; and 3) the variation in growth rates is equivalent to the variation in growth rates observed over the past 25 years (1996–2020).

From the above methodology, two views of probable outcomes form the forecast scenarios that were developed—the probability of exceeding and the probability of occurrence. The probability of exceeding indicates the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10 percent probability the actual growth rate will exceed the growth rate projected in the high scenario. The second probability estimate, the probability of occurrence, indicates the likelihood the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26 percent probability the actual

[12] Staff's Opening Comments at 8-9 (July 7, 2022) [hereinafter, "Staff's Comments"].
[13] Staff's Comments at 11.

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growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon.

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, irrigation, as well as additional firm load customers and historic system contracts, if applicable.

Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience. As a result, Idaho Power is confident that the modeled growth rate is reasonable and falls within the range of potential outcomes in both the near and long term. Idaho Power also notes that Staff's concern about long-term overstatement of growth is not related to the Company's near-term capacity needs, which are informed by substantial real growth across multiple sectors.

2. <u>Idaho Power's Regression Model - Residential</u>

With respect to the residential load forecast growth rate, Staff notes that Idaho Power's time series only goes back to 2011.[14] Staff believes this regression model should be tested against longer time periods.[15] Staff's Request for Company Reply Comments 2 and 3 ask the Company to explain how the problem of autocorrelation was resolved in Idaho Power's regression model for residential customers and why the data for residential regression model only goes back to 2011. Further, Staff asks why this same reasoning, of training periods beginning in 2011, does not apply to the regression models with longer time periods of historical data.[16]

Regarding autocorrelation, it is true that autocorrelation is a frequent issue with demographic-oriented models. Applying lagged adjustments can help for a single period. However, a persistent issue (that is throughout the time series) requires additional evaluation to

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[14] Staff's Comments at 10.
[15] Staff's Comments at 10.
[16] Staff's Comments at 11-12.

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ensure that lagged adjustments are reasonably applied; this work is presently ongoing. The Company uses an analysis of regression error including an inspection for out-of-bound values in the autocorrelation function ("ACF") and, where applicable, a partial autocorrelation function ("PACF"). In addition, the Company tracks serial/auto correlation in its residential models statistically using the Durbin-Watson metric, which does not indicate the presence of serial/auto correlation in its models (see Table 1).

The residential load forecast model is not an econometric-only model, as it relies upon end-use statistics to forecast future energy needs. Whereas economic drivers inform the residential forecast process, specific energy use intensities for appliances within a typical home play a more prominent role in shaping the residential load forecast. When tested, the model statistics for a training period[17] starting in 2011—in lieu of 1997 or 1995, for example—pointed to a model that was more stable (see Table 1 below). On the contrary, commercial and industrial use are direct elements of an economic forecast; the performance of such—as measured with out-of-sample testing—was significant and sufficient to continue using considering the variability that a richer historic data set provides (see Table 2 below).

Figure 1 below shows a comparison of Gross State Product for Idaho and the annual weather-adjusted energy sales for residential and commercial and industrial sectors. Starting in 2011, growth in the economic output for the state continues to show a strong correlation with the commercial and industrial sectors, whereas a shift in the correlation appears to exist for the residential sector.

Additionally, housing market dynamics have been undergoing usage changes generally independent from customer growth, primarily driven by energy efficiency. In applying the statistically adjusted end-use construct as the basis of the model, Idaho Power has found that

[17] A training period represents the term over the historical data that is used to build the impacts of each variable used in the regression analysis to estimate the forecast of future sales.

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these structural changes since 2011 are significantly incongruent with the residential model construct and could potentially lead toward over forecasting bias, further suggesting that using data from 2011 is appropriate for the residential framework.

Table 1 **Residential Model Statistics Using Different Training Periods**

SEQ	Model Statistics	Train Start 1995	Train Start 1997	Train Start 2011
1	Adjusted R-Squared	95.31%	95.92%	97.00%
2	Mean Squared Error	2375.9	2003.8	1229.2
3	Std. Error of Regression	48.7	44.8	35.1
4	Mean Abs. Dev. (MAD)	38.3	35	27
5	Mean Abs. % Err. (MAPE)	3.73%	3.45%	2.87%
6	Durbin-Watson Statistic	1.037	1.245	1.73
7	Skewness	0.294	0.289	-0.056
8	Kurtosis	2.74	2.777	2.371

Table 2 **Commercial and Industrial Select Model Out of Sample Tests**

Mfg_Ind	Model	Model Obs	Train Obs	Out of Sample	R^2 Adj	MAPE
	IRP	28			0.984	1.58%
	Training		19		0.967	1.71%
	Out of Sample			9		2.15%

Svc_Ind	Model	Model Obs	Train Obs	Out of Sample	R^2 Adj	MAPE
	IRP	28			0.992	1.21%
	Training		19		0.984	1.46%
	Out of Sample			9		1.26%

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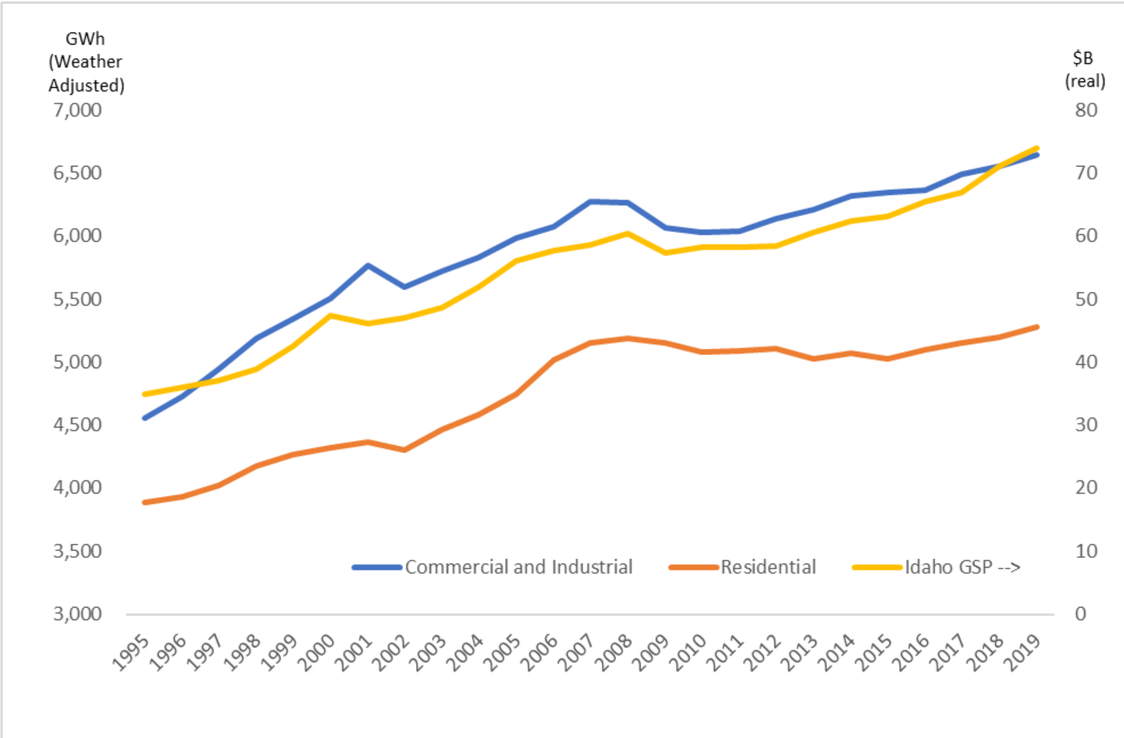
Figure 1 Weather-Adjusted Sales by Class to Gross State Product ("GSP")



3. <u>Idaho Power's Regression Model – Future Values of Independent Variables</u>

Staff's Request for Company Reply Comments 4 asks the Company to explain how the future values of the independent variables in its regression models are derived.[18] Idaho Power uses economic and demographic timeseries provided by third-party data providers. Moody's Analytics ("Moody's") and Woods and Poole are the primary sources. Moody's provides national and regional macro data based upon their U.S. Macro model. Woods and Poole provide data based on economic regions from the Bureau of Economic Analysis and is more micro-economic oriented.

Additionally, ITRON provides future variables for the Residential SAE inputs that reflect the U.S. Energy Information Administration's 2021 Annual Energy Outlook.

4. <u>Load Forecast - Large Industrial Customer Growth Assumptions</u>

Staff identifies 237 MW of "additional firm load" in the Company's Special Contract

[18] Staff's Comments at 12.

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customer load forecast and states there is insufficient detail to show why a growth rate of 24 percent can be reasonably expected through 2030.[19] Staff's Request for Company Reply Comments 5 asks the Company to explain the specific basis for each large industrial customer's growth in the additional firm load customer class.[20]

Each Special Contract, or additional firm load customer, is required to provide Idaho Power with a forecast of site-specific energy use. The 2021 IRP large load forecast was informed by customer-reported near-term growth by several existing large load customers, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Additionally, the Company has direct relationships with potential customers from the moment they express interest in the service area and use appropriate information about those specific projects to inform the large-customer load forecast. Through frequent communication, which includes ongoing updates and project load and timing, the Company can assess the probability of each potential project.

In addition to direct communication with customers, the Company maintains strong relationships with state and local community economic development professionals to enhance the Company's understanding of growth trends. The Company uses this information as a check on the reasonableness of customer forecasts.

While Idaho Power is limited in the detail it can publicly share with respect to specific large customer growth, the Company notes that, in 2021, Idaho was the fastest growing state in the country in terms of annual and cumulative population increase.[21] Further, three suburbs of

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[19] Staff's Comments at 9-10.
[20] Staff's Comments at 12.
[21] New Vintage 2021 Population Estimates Available for the Nation, States and Puerto Rico, U.S. Census Bureau (Dec. 21, 2021), https://www.census.gov/newsroom/press-releases/2021/2021-population-estimates.html ("Idaho had the fastest annual and cumulative population increase, growing by 2.9% (53,151) in the last year, and by 3.4% (61,817) since April 1, 2020.").

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Boise—Meridian, Caldwell, and Nampa (all in Idaho Power's service area)—were among the 15 fastest-growing cities or towns in the country, based on growth from July 2020 to July 2021.[22] These growth patterns and the associated commercial and industrial infrastructure required to support that growth are reflected in the large load growth forecast in the 2021 IRP.

5. Load Forecast – Impacts of Recent Economic Recovery

Staff expresses concern that the load forecast is based in part on the assumption that there will be continued improvement in the service area economy.[23] Staff's Request for Company Reply Comments 6 asks the Company to explain how Idaho Power's load forecast avoids extrapolating the growth rate of a recent economic recovery for the entire 20-year planning period.[24]

Extrapolation of a trend is distinguished from the underlying independent variables of a structural economic model; typically, economic trends in electricity sales are associated with underlying trends inherent in macro-economic variables such as Gross Domestic Product, which are not sufficiently robust to capture regional economic influences on energy consumption.

Idaho Power ensures that extrapolated growth rates are not overly influenced by recent trends by using techniques such as: segmentation of homogenous groups into economic cohorts to minimize spurious variable association and attendant trend errors; utilization of micro-economic drivers associated with North American Industrial Classification System ("NAICS")-level earnings variables; application of tests of robustness such as out-of-sample testing; and application of trend test-variables to ensure no underlying trend significance is inherent in the regression training periods.

[22] Fastest-Growing Cities Are Still in the West and South, U.S. Census Bureau (May 26, 2022), https://www.census.gov/newsroom/press-releases/2022/fastest-growing-cities-population-estimates.html ("Rounding out the list [of the 15 fastest-growing cities or towns] were three suburbs of Boise, Idaho: Meridian (5.2%), Caldwell (5.2%) and Nampa (5.0%).").
[23] Staff's Comments at 9.
[24] Staff's Comments at 12.

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6. Load Forecast – Impacts of COVID-19 on Load

Staff notes the Commission's order acknowledging the Second Amended 2019 IRP contained several action items. Staff has confirmed that Idaho Power has completed all but one. The action item yet to be completed is the requirement to "[p]resent to Commissioners the impact of COVID-19 on load."[25] Staff's Recommendation 1 (its sole recommendation) is for the Company to make a presentation to the Commission on the impact of COVID-19 on load at the August 18, 2022, workshop.[26] To fully satisfy this action item, the Company will present to the Commissioners a review of the impact of COVID-19 on load at the upcoming IRP workshop on August 18, 2022.

B. Effective Load Carrying Capability ("ELCC")

Staff calls attention to the Company's change in methodology of calculating the capacity contribution of variable energy resources ("VERs") from the last IRP and observes that the resulting effective load carrying capability ("ELCC") of some energy technologies appears on the low end of those Staff has seen elsewhere.[27] Acknowledging that estimating ELCC is very specific to a utility's own risk profile, Staff seeks to better understand why Idaho Power is finding lower ELCCs (specifically for wind) and plans to closely review the Company's modeling in MATLAB.[28]

The ELCC calculations utilized in the 2021 IRP ultimately represent a methodology that is compliant with the Commission's Order No. 16-326. For background, in the 2019 IRP, Staff expressed concern that the Company was utilizing methods to determine the capacity contribution of VERs that were not in compliance with Order No. 16-326.[29] Prior to the 2019 IRP, the Company utilized the Capacity Factor ("CF") approximation method because, at the time, the Company had

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[25] Staff's Comments at 5.
[26] Staff's Comments at 11.
[27] Staff's Comments at 12-13.
[28] Staff's Comments at 13. MATLAB® is a proprietary programming language and computing environment developed by MathWorks.
[29] *See In re Idaho Power Company, 2019 Integrated Resource Plan*, Docket No. LC 74, Staff's Final Comments at 16-17 (Jan. 8, 2021); Docket No. LC 74, Staff's Opening Comments at 16 (Apr. 1, 2020).

no actual on-system solar data on which to base more detailed capacity calculations.[30] In the 2019 IRP, neither the CF nor ELCC approaches were tenable to serve long-term resource planning needs. As the Company went from zero solar capacity to 289 MW of capacity in a single year, and as modeled portfolios included over 1,000 MW of new solar generation, the CF approximation method was demonstrably inadequate for modeling solar's capacity value at this scale.[31] At the same time, the rapidity of the solar penetration spike meant that there was insufficient longitudinal data to perform the ELCC calculation, which requires 3-5 years of operational data.[32] As a result, Idaho Power, in consultation with Staff, made a good faith effort to bridge the gap between these methods, using the 8,760-based method, a highly reputable variation of the ELCC calculation, developed by the National Renewable Energy Laboratory ("NREL"). For the 2021 IRP and with sufficient solar data, Idaho Power transitioned to the full ELCC method. The Company believes the resulting ELCCs are accurate and the methodology itself, apart from being compliant with the Commission's order, represents an improvement over the prior methods.

As an example of its ELCC concerns, Staff states: "the Company assumes an ELCC of 11.2 percent for wind. This falls between the last IRP's assumption of 5 percent for peak planning and annual average capacity factors of 35 percent for projects sited in Idaho and 45 percent for projects in Wyoming."[33] Regarding Staff's example, the Company would like to clarify that *capacity contribution* and *capacity factor* are not the same and should not be directly compared. Capacity

[30] In re Public Utility Commission of Oregon Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Docket No. UM 1719, Idaho Power's Opening Testimony of Rick Haener, Idaho Power/100, Haener/5 (Dec. 14, 2015) ("[C]urrently, there are no utility-scale solar PV projects connected to Idaho Power's system; consequently, no actual PV generation data is available[.]"); see also Docket No. LC 74, Idaho Power's Reply Comments at 40-43 (May 15, 2020).
[31] *See* Docket No. LC 74, Idaho Power's Reply Comments at 40-43.
[32] Extrapolating solar data to model more years for the analysis would be detrimental to the calculation because the outage rates of these plants and the necessary relationship between load and generation would be lost. While using such methodologies can be valuable in predicting the energy generated from a solar plant on a yearly basis, they should not be used for studies pertaining to reliability, or in this case, capacity contribution.
[33] Staff's Comments at 13.

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contribution is a measure of a power plant's generation contribution to system capacity during high-risk hours while capacity factor is a measure of how much average energy is produced by a resource in comparison to its nameplate output. As an example, peaking generation plants often have high-capacity contributions as they run when they are needed during peak hours, but have low capacity factors because they do not run for most of the year.

For the 2021 IRP, Idaho Power modeled both Idaho- and Wyoming-sited wind. Each resource was modeled with its own characteristics (e.g., hourly output and capacity factor) using NREL's System Advisor Model ("SAM"); the modeled capacity factor for Idaho and Wyoming wind resulted in 35 percent and 48 percent, respectively. Idaho Power used four years (2017-2020) of historical data to calculate the capacity contribution, or ELCC, for wind and solar resources. The Company does not have any historical data for Wyoming-sited wind, so the NREL data from SAM was used to test the Wyoming wind ELCC calculation. The ELCC of the generic (non-specific year) Wyoming wind profile was similar to the result of the Idaho wind ELCC; therefore, both project types were assigned the same ELCC. Notably, Idaho Power is a summer-peaking utility and wind output is generally negatively correlated with hot weather,[34] making the low wind ELCC's reasonable. Considering the notable differences between seasonal peaks and technology performance in hot weather, the Company cautions against direct comparison between winter peaking utilities' ELCCs and summer peaking utilities' ELCCs. The Company recognizes Staff's interest in the Company's ELCC methodology and modeling in MATLAB and will work in collaboration with Staff to build its knowledge on the subject.

[34] Astrapé Consulting and Energy + Environmental Economics, Incremental ELCC Study for Mid-Term Reliability Procurement at 32 (Aug. 31, 2021), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20210831_irp_e3_astrape_incremental_elcc_study.pdf.

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C. Demand Response ("DR")

1. DR Potential

Staff has many questions about how DR has been treated in the 2021 IRP, most of which are related to understanding why the Preferred Portfolio did not select all potential DR.[35] Staff seeks to understand the factors impacting DR selection.[36] In particular, Staff would like to understand how the Company arrived at DR costs and DR capacity and whether the declining capacity contribution for future DR is consistent with the Company's modeling of other resources.[37] Notably, Staff's initial impression was that DR cost assumptions appear reasonable and that the fact that the Preferred Portfolio did not select all potential DR is not likely due to unreasonably high DR cost assumptions.[38]

While there are numerous ways to determine the achievable potential of DR, it is important to note that the amount of DR available for selection in the 2021 IRP was more than sufficient to optimize resources to meet system needs. Out of 280 MW of incremental DR available for selection in the model (along with 300 MW of existing DR), 100 MW of additional DR was selected in the Preferred Portfolio.[39] The reasonableness of the additional DR amounts was tested by forcing the selection of *more than* 100 MW of DR early in the planning timeframe, which ultimately increased portfolio costs when compared to the Preferred Portfolio.[40]

2. DR Assumed Capacity

In the 2021 IRP, Idaho Power relied on the ELCC method of measuring capacity contribution, which resulted in reduced effectiveness of its existing DR programs as compared to the last IRP.[41] The Company proposed, and the Commission approved, changes to Idaho Power's

[35] Staff's Comments at 13.
[36] Staff's Comments at 14.
[37] Staff's Comments at 14.
[38] Staff's Comments at 14.
[39] 2021 IRP at 5, 69.
[40] 2021 IRP at 123.
[41] Staff's Comments at 14.

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DR programs in Advice No. 21-12.[42] The changes were made to better align the program parameters with the highest-risk hours, resulting in a higher ELCC of 56 percent (when compared to 17 percent based on the same method applied to the prior program parameters).[43] Given all the modifications, Staff would like to better understand how DR capacity is calculated and has requested the Company provide additional information around the assumed capacity for existing DR in the 2021 IRP.

Staff's Request for Company Reply Comments 7 asks Idaho Power to provide the observed nameplate capacity and ELCC of the Company's DR programs in the current peak season of 2022.[44] While the Company is unable to provide the observed capacity and ELCC of the Company's DR programs for the 2022 peak season because the Company is in the middle of its 2022 peak season and cannot yet determine these values, as of the start of the 2022 program season, the Company had approximately 320 MW of expected capacity. Once the peak season has concluded, and the Company has had sufficient opportunity to properly analyze the necessary data, the Company will evaluate the performance of the DR programs for the 2022 peak season and will rely on that information to inform DR capacity and ELCC values to be used in future modeling.

Staff's Request for Company Reply Comments 8 asks the Company to provide the characteristics of DR considered in the calculations of DR nameplate capacity and ELCC, the degree to which each characteristic impacts the capacity total, and to provide the basis for the Company's decision to assign a specific value for each characteristic.[45] The characteristics considered in the ELCC calculation of existing DR included the maximum number of events per week and season, the start and end time of each event, the group size, and the start and end

[42] *Idaho Power Advice No. 21-12 Proposed Modifications to DR Programs*, Docket No. ADV 1355, Commission Adoption of Staff Recommendation (Feb. 8, 2022).
[43] Docket No. ADV 1355, Commission Adoption of Staff Recommendation at 7.
[44] Staff's Comments at 18.
[45] Staff's Comments at 18.

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date of the DR season. Each of these parameters were adjusted based on their ability to meet demand during the hours of highest system risk. While the impacts of these characteristics were not evaluated in isolation, the aggregate of the adjustments resulted in an improved ELCC value of 56 percent compared to the ELCC value of 17 percent for the unadjusted DR programs.

Additionally, the Company considered customer impact of each parameter change through customer surveys of current and potential participants of the Company's DR programs. The survey results were utilized to help estimate the nameplate capacity of the program under the new parameters.

More information about the survey and results, as well as parameters chosen for the programs and their impact on ELCC are further described in Docket No. ADV 1355, Idaho Power Advice No. 21-12, Proposed Modifications to DR Programs.[46]

3. DR Modeling in AURORA

Idaho Power uses AURORA's forced outage rate function to manually enter the periods during which DR is available. Staff explains that most hours have a forced outage rate of 100 percent, preventing DR from selection, which makes sense for hours outside the DR program parameters but does not for hours within the event parameters with a forced outage rate.[47] The Company explained to Staff that use of the forced outage rate was to account for the limited number of events that can be called. Staff is concerned that the way DR is being modeled is affecting its utilization and would like to better understand how DR is made available for selection in AURORA.[48]

Staff's Request for Company Reply Comments 11 asks the Company to explain how the hours when DR was given a forced outage rate less than 100 percent were chosen.[49] The hours

[46] Docket No. ADV 1355, Proposed Modifications to the Company's Demand Response Programs, Attachments 2 & 4 (Nov. 23, 2021).
[47] Staff's Comments at 16.
[48] Staff's Comments at 16.
[49] Staff's Comments at 18.

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when DR was used, or given a forced outage rate less than 100 percent, were computed by Idaho Power's internally developed Loss of Load Expectation ("LOLE") tool, which determines when DR would be the most beneficial to the system. The LOLE tool identifies the hours of highest risk. Using the hours of highest risk and all of the constraints associated with the different DR programs, the tool created an hourly dispatch shape for the DR portfolio. The load profile and resources in a given year have a significant influence on the DR dispatch hours and days, and thus a different DR dispatch shape was created for each year of the planning horizon. Idaho Power updated the DR dispatch by iterating preliminary results of the LTCE model to account for the different resources being added to the system. The hourly dispatch for each year was then converted into a forced outage rate to match AURORA's formatting requirements for a resource.

Staff also notes that for the 2021 IRP, AURORA was allowed to select DR from potential future resources in capacity blocks of 20 MW compared to the Second Amended 2019 IRP, in which the DR available for selection was in capacity blocks of 5 MW.[50] Staff's Request for Company Reply Comments 10 asks Idaho Power to explain why the size of a new DR block was increased since the last IRP.[51] The Company reviews and updates input assumptions every IRP cycle prior to conducting the IRP analysis. Idaho Power's DR program expansion potential of 284 MW in the 2021 IRP leveraged the amount of achievable DR identified in the Northwest Power and Conservation Council's ("NWPCC") assessment of DR.[52] DR programs take time to plan, structure, promote, and implement. While the new annual amount of DR that is selectable is larger than the 5 MW annual amount available in the previous IRP, Idaho Power believes the use of 20 MW blocks more accurately reflects that a program could achieve up to 20 MW in a given year if

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[50] Staff's Comments at 17.
[51] Staff's Comments at 18.
[52] 2021 IRP at 68-69. Note that there is a total of 584 MW of potential DR in Idaho Power's service area, and Idaho Power already has 300 MW in the Company's existing DR programs. Accordingly, Idaho Power's DR expansion potential is 284 MW.

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the customer potential was accurately estimated. Furthermore, the use of 20 MW blocks gave AURORA more DR to fill a potential deficit if needed.

4. DR's Declining Capacity Contribution

On June 13, 2022, Staff met with the Company to discuss questions about DR, including changes to DR's ELCC. Idaho Power explained that additional DR resources *will not* maintain an ELCC of approximately 56 percent but rather experience an ELCC decline per 20 MW increment. In other words, the effectiveness of DR does not increase at the same rate as nameplate capacity and the capacity contribution of new DR diminishes as the total amount of DR grows. This decline in ELCC as resources are added is not unique to DR. It is observed in other resources, including solar, storage, and wind.

Staff's Request for Company Reply Comments 9 asks the Company to explain whether the varied ELCC of different tranches of potential DR is an outcome of the IRP modeling exercise or based on exogenous characteristics assigned to the 20 MW increments of new DR.[53] The decline in ELCC is a function of the Company's DR having limited flexibility to operate. The DR programs are constrained by the number of hours per day, week, and season, as well as the time of day and season. The same declining ELCC was observed with other resources such as solar and storage, where adding a resource with the same characteristics results in decreased effectiveness at meeting the highest-risk hours. The ELCC for future DR was calculated using the same method as all other VERs in the 2021 IRP—that is, it was calculated using the last-in ELCC.

D. Resource Economics

1. Wholesale Electricity Prices

Staff is concerned that Idaho Power's forecast Mid-Columbia ("Mid-C") prices are too low, creating bias for storage and transmission resources.[54] Generally, Staff seeks to understand why

[53] Staff's Comments at 18.
[54] Staff's Comments at 18-19.

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the AURORA-modeled Mid-C prices are a good proxy for future wholesale prices.[55]

2. AURORA Modeled Mid-C Prices vs. Historical Actuals

Staff believes that Idaho Power's wholesale electric price forecast appears low and can bias the selection of storage and transmission resources.[56] Staff would like to see how accurate the 2021 forecast prices are compared to actual Mid-C prices in 2021.[57] Specifically, Staff's Request for Company Reply Comments 12 is to compare the 2021 IRP's Mid-C forecast under low hydro conditions in 2021 with observed 2021 market prices.[58]

The Company is unable to perform Staff's request to generate Mid-C forecast prices in AURORA based on 2021 hydro conditions. Mid-C prices are influenced by myriad factors over vast and diverse geographies across the Western Interconnection, for which accurate historical data is not available to the Company. Instead, the ex-ante wholesale prices generated by AURORA are based on typical or planning conditions generated before actual conditions occur. It should not be a surprise, then, that actual wholesale prices differ from AURORA's ex-ante modeled prices. AURORA is a sophisticated modeling platform that generates many zonal prices based on economic fundamentals, but it is not able to perfectly predict or exactly match the real time conditions and nuances of energy markets. In 2021, energy markets moved due to drought conditions throughout the Western Electricity Coordinating Council ("WECC"),[59] one in 1,000-year type weather events in the Pacific Northwest,[60] post-pandemic related gas supply issues

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[55] Staff's Comments at 18-19.
[56] Staff's Comments at 18-19.
[57] Staff's Comments at 18.
[58] Staff's Comments at 19.
[59] *See* U.S. Drought Monitor for December 28, 2021 (Dec. 30, 2021), *available at* https://droughtmonitor.unl.edu/data/png/20211228/20211228_usdm.png
[60] Jason Samenow and Ian Livingston, Canada sets new all-time heat record of 121 degrees amid unprecedented heat wave, Washington Post (June 29, 2021), https://www.washingtonpost.com/weather/2021/06/27/heat-records-pacific-northwest/.

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throughout the United States,[61] localized natural gas pipeline disruptions,[62] and wildfire disruptions to transmission infrastructure,[63] amongst many other widely reported events with hard-to-quantify influence on market prices. Further, there are many smaller but significant events that do not make headlines, are not reported, and still impact market conditions. The Company believes that AURORA would perform well if all the pertinent data were available to perform a rigorous ex-post modeling of Mid-C prices.

Even with recognized differences between ex-ante forecasted and actual market values, forecasted market prices are useful for planning purposes. Using typical or planning conditions and reserve margins, the IRP process presents a reasonable least-cost representation of likely future resource decisions and is not designed to serve as an exact plan to be executed. Nevertheless, the Company compared its WECC build out to that of the NWPCC and found the Company's 2021 build out was generally aligned with the WECC buildout of the NWPCC,[64] which anticipates new generation will largely be confined to wind, solar, and storage resources. Based on this and other assessments, the Company can infer that its modeled Mid-C forecast prices are consistent with (that is, within range of) those forecast by other entities.

With reference to Staff's belief that the Preferred Portfolio's buildout of storage resources is a product of wholesale market prices, the two are largely unrelated. Staff posits that "Idaho Power expects an arbitrage opportunity to make storage resources more economic."[65] Arbitrage is a value stream; however, the primary value of storage is its peaking capability. In AURORA,

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[61] Surging Natural Gas Prices: Threat to Consumers This Winter?, U.S. News (Associated Press, Sept. 30, 2021), https://www.usnews.com/news/business/articles/2021-09-30/surging-natural-gas-prices-threat-to-consumers-this-winter

[62] Nia Williams, Pipeline firms scramble to restore service after British Columbia floods, gas prices spike, Reuters (Nov. 17, 2021), https://www.reuters.com/world/americas/pipeline-firms-scramble-restore-service-after-british-columbia-floods-gas-prices-2021-11-17/

[63] Oregon wildfire robs California of critical electricity supply from Pacific Northwest during heat wave, The Oregonian, (July 16, 2021), https://www.oregonlive.com/wildfires/2021/07/oregon-wildfire-robs-california-of-critical-electricity-supply-from-pacific-northwest-during-heatwave.html

[64] WECC-Wide Buildout Results, NWPCC, https://www.nwcouncil.org/2021powerplan_wecc-wide-buildout-results/ (last visited July 29, 2022).

[65] Staff's Comments at 19

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the Company models storage as a capacity resource during times of high net peak demand. The model charges storage resources during periods of low net demand and discharges them during periods of high net demand—if the Company were seeking storage for arbitrage only, the expectation is that fewer storage resources would be included in the plan. That is, the Company's storage dispatch structure and timing does not indicate the deployment of storage solely for arbitrage.

3. AURORA Wholesale Prices and WECC Resources

Because AURORA produces wholesale price forecasts based on expected resources in the WECC, Staff believes that a heavy storage buildout will smooth out wholesale energy prices and remove arbitrage opportunities the Company seeks to exploit.[66] Staff's Request for Company Reply Comments 13 asks the Company to describe the basis for the 2021 IRP's forecast of WECC resources and their associated availability.[67] The 2021 IRP WECC resources and their associated availability are produced by the AURORA LTCE model. This WECC LTCE buildout was then benchmarked against the NWPCC's 2021 Power Plan, which was largely derived based on clean and renewable energy public policy requirements across the West. Idaho Power feels the WECC buildout in the 2021 IRP is comparable to other industry forecasted future WECC resource buildouts.

4. AURORA Modeled Mid-C Prices vs Forecast

Because Idaho Power's AURORA-based Mid-C forecast is significantly lower than the prices the Company uses to set Public Utility Regulatory Policies Act ("PURPA") prices in UM 1730,[68] Staff's Request for Company Reply Comments 14 is for the Company to graph the 2021 IRP's Mid-C and Palo Verde forecasts with the latest forward price curves of these markets

[66] Staff's Comments at 19.
[67] Staff's Comments at 19.
[68] The forecast prices in UM 1730 use observed forward prices from the Intercontinental Exchange.

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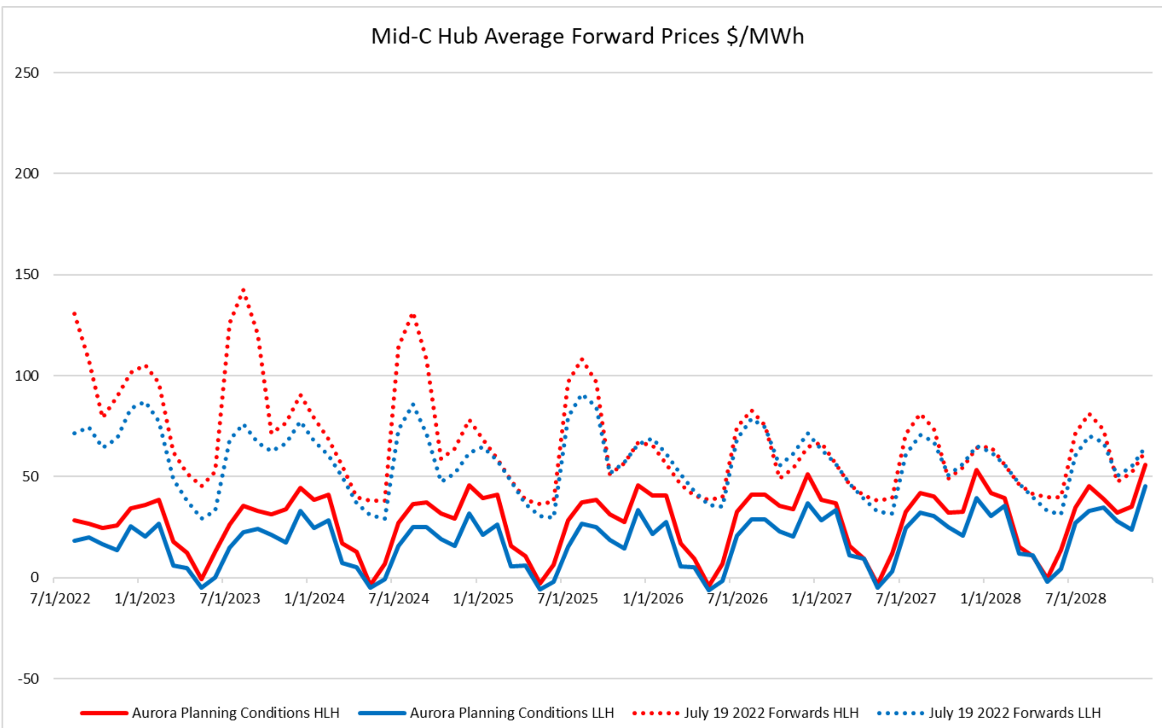
and explain how and why Idaho Power's AURORA modeling is more reasonable than observed market prices.[69]

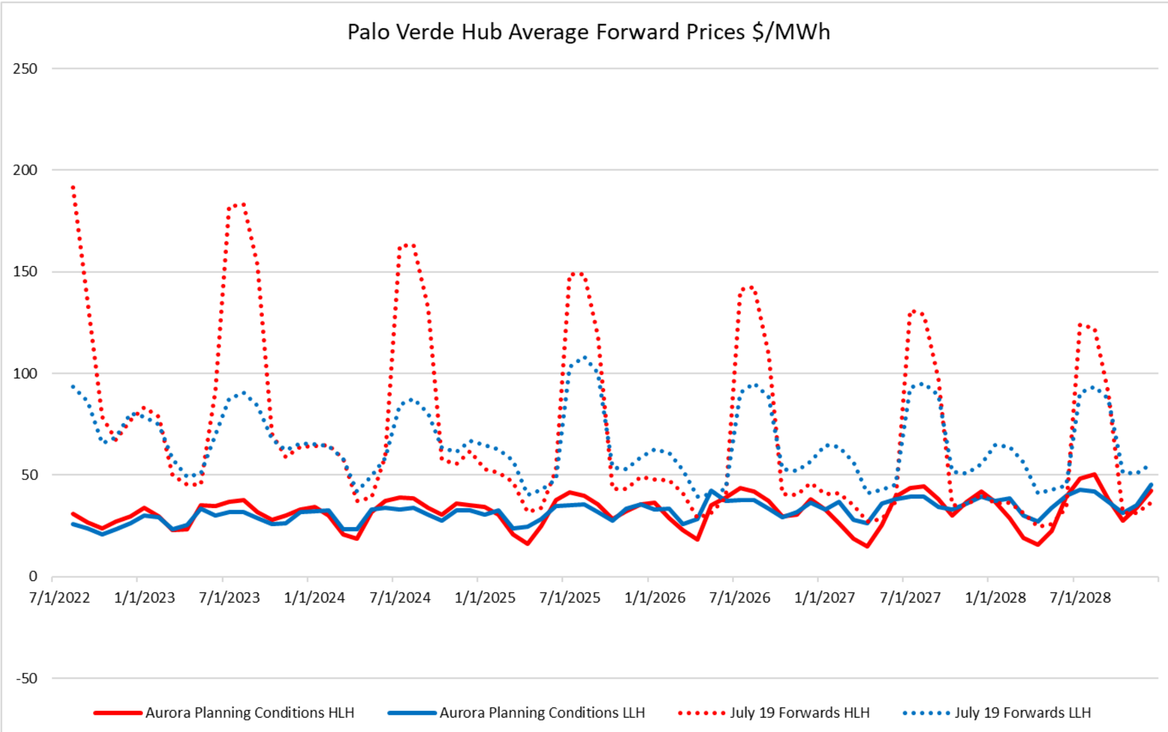
Forward price curves are ever evolving and, as such, today's observable forward market prices were not available at the time the 2021 IRP was developed. Nevertheless, Figures 2 and 3 show the latest price curves (circa July 19, 2022) graphed against the planning condition prices from the AURORA model for Mid-C and Palo Verde.

Figure 2 Mid-C Hub Average Forward Prices $/MWh vs AURORA Planning Conditions



[69] Staff's Comments at 19.

Figure 3 Palo Verde Hub Average Forward Prices $/MWh vs AURORA Planning Conditions



In near-term years, AURORA is not designed to capture price spikes as it does not have a scarcity pricing mechanism. As can be observed in Figures 2 and 3 above, the actual forward price curves begin to converge with the planning condition market prices derived within AURORA in later years. There is a discrepancy between early year model-derived prices and actual forecast prices due, in part, to economic and real-world events that were unknown and unknowable at the time the 2021 modeling was developed.

Although there are differences in the near-term AURORA modeled prices compared to current forward price curves, the Company observes consistent directional movement with convergence over time. It is likely that the current forward price curves are not reflecting the IRP model's expected major shift to renewable resources (solar, solar plus storage, and wind) over the coming years, driven by both public policy requirements and economics, and the impact those renewable resources will have on energy prices in the West.

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5. Combined Cycle Combustion Turbine ("CCCT")

Staff finds all the assumed costs for a CCCT plant to be reasonable except the initial capital cost.[70] Staff's Request for Company Reply Comments 15 requests an explanation why Idaho Power's method of estimating the capital cost of a CCCT is more reasonable than citing contemporary research from either NREL or Lazard, as the Company does for other resources.[71] To estimate initial capital costs of the CCCT, Idaho Power leveraged its direct experience building a CCCT by starting with the cost data from the construction of the Langley Gulch Power Plant. The Company believes the combination of actual prior cost data (not estimated) from constructing a CCCT in its own service area, together with the information received from Siemens supports the Company's use of an internally developed capital cost estimate, rather than a general technology estimate. NREL and Lazard provide broad national estimates for resource costs and do not necessarily reflect the unique characteristics of Idaho Power's region such as altitude, climate, and geographic remoteness.

Moreover, the Company validated its capital cost assumptions with peer utilities and the national vendors. Idaho Power's CCCT capital costs for the 2021 IRP are within the range of those used by the Company's regional peers in their most recent IRP cycle. For example, PacifiCorp's 2021 IRP estimated CCCT capital costs (for a plant of comparable size) ranging from $1,396 - $1,761 per kW (in 2020 dollars).[72] Idaho Power included a 20 percent adder on top of its CCCT capital cost estimate for potential alternative fuel blending. With this 20 percent adder removed, the base CCCT capital cost estimate is within 6 percent of Lazard's upper range value of $1,300 per kW. While the Company believes its internally developed cost estimate is

[70] Staff's Comments at 19.
[71] Staff's Comments at 20.
[72] PacifiCorp 2021 Integrated Resource Plan, Vol. I at 169-170 (Sept. 1, 2021), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf [hereinafter, "PacifiCorp 2021 IRP"].

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reasonable, the Company will continue to evaluate IRP cost inputs, share these results with the IRP Advisory Council ("IRPAC"), and adjust as necessary in future IRPs.

6. Battery Storage

In the 2021 IRP, the Company modeled a combination of a VER with storage at a 1:1 ratio. Staff believes that other pairing ratios should have been modeled and these additional resource options should be added for modeling in the future.[73] Further, Staff considers the Company's battery storage cost assumptions to be optimistically low.[74] Staff's Request for Company Reply Comments 16 and 17 ask the Company to explain why only a 1:1 ratio was used for storage sited with solar and to provide the capital costs from battery storage bids Idaho Power has received in its current Requests for Proposal ("RFP").[75]

Idaho Power chose to model 1:1 solar to storage resources (1 MW of solar for every 1 MW of storage) in its 2021 IRP based on analysis that showed the 1:1 ratio had a higher peak capacity than lower ratios. In addition to the 1:1 solar and storage resource, the model could select solar and storage separately to achieve an optimal resource mix to meet system needs. Idaho Power discussed this decision with its IRPAC during its May 13, 2021, presentation titled Future Supply-side Resource Options.[76] Stakeholders were aligned with modeling only a 1:1 ratio with solar and storage separately selectable. Another factor leading to the Company's decision was model run time constraints. Increased resource options in the AURORA model result in longer run times—especially with respect to storage and storage dispatch.

Idaho Power's battery storage cost estimates are within the range of estimates used by other regional utilities and entities in recent planning cycles. Avista's 2021 IRP includes 4-hour

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[73] Staff's Comments at 20.
[74] Staff's Comments at 20.
[75] Staff's Comments at 20-21.
[76] Idaho Power, Future Supply Side Resource Costs for 2021 IRP (May 13, 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/IRPAC_FutureResource%20Costs_May2021.pdf.

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lithium-ion battery storage costs of $1,288/kW in 2020 dollars.[77] The NWPCC 2021 Power Plan includes a capital cost assumption of $1,400/kW in 2016 dollars.[78] NREL's 2021 Annual Technology Baseline ("ATB") reports historical costs of $1,363/kW for 2020 and had a 2021 projected cost of $1,250/kW.[79] Given the timeframe of when the 2021 IRP battery capital cost assumptions were determined, Idaho Power believes a comparison to the 2021 NREL ATB data is most appropriate.

Idaho Power strives to use the best data available at the time costs are estimated for the IRP. Although 2022 data may not support the Company's 2021 IRP battery cost assumptions, it should be noted that every major national data source for future lithium-ion battery costs in 2021 and beyond projected continued downward trends in cost. Unpredictable global events from year-to-year can have great impact on resource cost variability, as seen in 2022 for virtually all resources, not just battery storage. Idaho Power's battery cost assumption in the 2021 IRP was based on credible data and should be considered reasonable based on what was known at the time. Notwithstanding, the Company will continue to analyze future market conditions to inform resource cost assumptions for the 2023 IRP.

Staff's Request 17 asked the Company to provide capital costs from battery storage bids Idaho Power has received in its current RFPs. The requested information is highly sensitive and therefore the Company is working with the parties to this docket on terms for a Modified Protective Order that would provide adequate protections. Once a Modified Protective Order is in place the Company will provide the bid information in accordance with its terms as Attachment 1 to these Reply Comments.

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[77] Avista 2021 Electric Integrated Resource Plan at 9-13 (2021), *available at* https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2021-electric-irp-w-cover-updated.pdf.

[78] Northwest Power and Conservation Council, The 2021 Northwest Power Plan at 66 (Mar. 10, 2022), *available at* https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf [hereinafter, "2021 Northwest Power Plan"].

[79] Utility-Scale Battery Storage, NREL, https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage#capital_expenditures_(capex).

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7. Transmission

Staff identifies four changes in transmission assumptions compared to the Company's prior IRP. Staff's comments focus on the impact of the changes to B2H ownership, asset swaps, and other transmission projects that might relieve access to wholesale markets without investing in SWIP-North.[80]

8. Idaho Power's Expanded B2H Ownership

One of the Company's commitments made at the conclusion of its Second Amended 2019 IRP was to include modeling of B2H partnership costs and risks in the 2021 IRP. Per the Commission's order in the Second Amended 2019 IRP, the Company was expected in the 2021 IRP to conduct a more in-depth analysis of cost risk associated with B2H, including an analysis of whether expanding its ownership share from 21 percent and relying on Open Access Transmission Tariff ("OATT") revenues to offset its additional costs was comparable to joint ownership, in terms of risks and financial impacts. Staff concludes the 2021 IRP did not include detailed analysis of the cost of B2H before and after the ownership change to give Staff the ability to compare the financial impacts and risks to customers.[81] Additionally, given the non-binding nature of the B2H term sheet, Staff believes the ownership structure may remain unsettled.[82] Staff recommends studying a 100 percent ownership arrangement to capture the risk that PacifiCorp might seek the same arrangement as Bonneville Power Administration ("BPA").[83] Staff's Request for Company Reply Comments 18 asks the Company to describe the probability Idaho Power's ownership share of B2H will increase again.[84]

First, with respect to Staff's concern about future changes to the contemplated ownership arrangements, absent a change in capacity needs, the Company believes the probability is low

[80] Staff's Comments at 21.
[81] Staff's Comments at 22.
[82] Staff's Comments at 22.
[83] Staff's Comments at 22.
[84] Staff's Comments at 24.

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that the Company's ownership share will increase again. In fact, PacifiCorp includes the B2H line as Action Item 3c in its 2021 IRP[85] and the B2H partners are actively working on contractual agreements following the agreed upon terms from the February 2022 Term Sheet. The parties are not currently pursuing any alternative B2H ownership structures; however, the final ownership shares may change if unsubscribed capacity in the east-to-west direction on B2H later becomes subscribed, which would further reduce the cost of the project on a cost-per-unit capacity basis.

Second, the Company recognizes Staff's concern that the 2021 IRP did not include a detailed analysis of the cost of B2H before and after the ownership change to give Staff the ability to compare the financial impacts and risks to customers.[86] However, the Company believes that direct comparisons between the originally-contemplated and the currently-agreed-upon ownership arrangements would not be valid, which is why the Company opted for a more straightforward cost-risk analysis.

The three parties to the Term Sheet (Idaho Power, PacifiCorp, and BPA) negotiated a highly complex three-party arrangement, meeting each of the party's needs. In this arrangement, Idaho Power will own approximately 45 percent of the project—other ownership amounts were not contemplated. As a result, analyzing a 21 percent ownership structure in light of the Term Sheet would be an entirely hypothetical exercise that would yield no meaningful insights. While it may seem like a simple ask, evaluating at a 21 percent ownership scenario would require either (1) major assumptions on what a final negotiated three-party structure with Idaho Power's ownership at 21 percent would look like, or (2) taking a big step back to previous IRPs when the Company focused only on its own costs and needs associated with the project, and assumed the other B2H parties' needs would not impact the B2H business case, which is not a realistic representation of a major regional project like B2H. In the case of option (1), the Company did not feel comfortable speculating what the other parties would have agreed to with the Company only

[85] PacifiCorp 2021 IRP at 27.
[86] Staff's Comments at 22.

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owning 21 percent. On this point, it is important to remember that the permitting agreement, which included the original 21 percent ownership share, was a preliminary agreement and did not address all of the details that the parties might include in a construction agreement. Moreover, to be clear, there is only one ownership arrangement on the table—the one agreed to by all three parties-- and the Commission should not assume that it would have been possible for Idaho Power to come to agreement for a 21 percent ownership share even if it wanted to. Therefore, even if the Company was able to make an accurate and apples-to-apples comparison between the originally contemplated and currently agreed-upon ownership arrangements, it would be relatively meaningless.

In the case of option (2), the Company did not see the value in determining whether that option would look better or worse than the negotiated and agreed-to Idaho Power 45 percent ownership share, as specified in the Term Sheet because it is not a realistic representation of a major regional project and associated benefits to Idaho Power customers.

The Term Sheet is non-binding, but it contains terms agreed to by all three parties. As such, Idaho Power fully implemented the parameters of the Term Sheet when studying B2H within the 2021 IRP. The clearest alternative to the Company owning 45 percent of B2H, under the Term Sheet parameters, is B2H not being constructed. The Company evaluated this alternative at length in the 2021 IRP. Lastly, the Company performed extensive evaluation of B2H project costs and risks in its B2H robustness tests, which included capacity/market availability, project cost variability, and in-service date delays.[87]

Because the B2H Term Sheet is non-binding, Staff is concerned that the ownership structure may remain unsettled and the Company should have studied a 100 percent ownership arrangement that would look at the risk that PacifiCorp might seek the same deal as BPA, namely, to let Idaho Power assume the hazards of ownership and instead pay the Company the OATT.[88]

[87] 2021 IRP at 144-146.
[88] Staff's Comments at 22.

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Staff would like the Company to describe how likely it is that this scenario might emerge.[89] Idaho Power did not perform this analysis because the Company does not believe this scenario is likely to emerge. As the Company has stated previously, if PacifiCorp were to elect to not move forward with the B2H project, the Company would reevaluate its options and likely seek a replacement partner. Therefore, a 100 percent ownership scenario is very unlikely.

Considering the extensive analysis and stress testing specific to B2H, Idaho Power is confident the 2021 IRP appropriately assesses B2H partnership costs and risks, consistent with assumptions the Company agreed to provide as part of the Second Amended 2019 IRP process.

9. Projected BPA OATT Revenue for B2H

Staff analyzed the annual revenue streams from BPA and confirmed that projected revenues can offset the increased costs. However, those annual revenue numbers are hardcoded, making them difficult to assess. Staff's Request for Company Reply Comments 19 is for a description of the assumptions behind the projected revenue estimates from BPA's use of B2H.[90]

With the addition of B2H, Idaho Power will provide network transmission service to BPA to deliver energy to their southeast Idaho load. As such, they will be billed according to the charge provisions for Network Integration Transmission Service ("Network Customer") described in Schedule 9 of Idaho Power's OATT, which is updated annually as part of the Company's Federal Energy Regulatory Commission ("FERC") Formula Rate process. For the projected OATT revenue estimate, the Company modeled the forecasted BPA Southeast Idaho monthly peak demand to be 359 MW in 2026 and then applied a 1.1 percent growth rate in future years. The increased BPA network load on the Idaho Power system coupled with the forecasted transmission rate from the Company's FERC Formula Rate process is projected to result in increased transmission service revenue from BPA to Idaho Power that will offset overall B2H-related costs.

[89] Staff's Comments at 22.
[90] Staff's Comments at 24.

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10. B2H Asset Swaps

Staff discusses the asset swaps and upgrades that are part of the B2H negotiations and speculates they may result in a net cost.[91] If these swaps and upgrades are necessary for the B2H project, Staff believes the net costs should be included in the total cost for B2H.[92] On the other hand, if they are not necessary for the B2H project, each of these projects should be weighed on their own merits.[93] Staff's Request for Company Reply Comments 20 and 21 is a description of the necessity of each asset swap and upgrade (as mentioned in the 2021 IRP's Appendix D pages 6 – 9) to the engineering of B2H and for an itemized cost of each asset swap and upgrade.[94]

The B2H-related asset swaps and upgrades are all necessary components of the B2H Term Sheet in order to meet each party's needs. The PacifiCorp assets to be acquired from Idaho Power are required by PacifiCorp to utilize B2H's incremental capacity, and the Idaho Power assets to be acquired from PacifiCorp are in consideration of the assets Idaho Power is providing to PacifiCorp. The Midpoint-Kinport 345 kilovolt ("kV") Series Capacitor Addition and the Midpoint 500/345 kV Second Transformer Addition are necessary to relieve transmission bottlenecks across the southern Idaho transmission system on the Borah West and Midpoint West transmission paths to support additional east-to-west transmission flows with B2H. Without the proposed upgrades, PacifiCorp could not access their 600 MW of east-to-west capacity on the project, and relieve Idaho Power of its existing 510 MW transmission service obligation.

The 2021 IRP analysis conservatively assumed Idaho Power would pay the full cost of the Midpoint-Kinport 345 kV Series Capacitor and the Midpoint 500/345kV Second Transformer upgrades. The Company made this assumption because it is continuing to work with PacifiCorp to determine a cost estimate associated with the asset swap. The actual total cost responsibility

[91] Staff's Comments at 23.
[92] Staff's Comments at 23.
[93] Staff's Comments at 23.
[94] Staff's Comments at 24.

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(upgrades and swap) for Idaho Power will likely be less than the cost modeled in the 2021 IRP and will be determined as Idaho Power and PacifiCorp work through the details of the asset exchange associated with B2H.

The estimated project costs of the Midpoint-Kinport 345 kV Series Capacitor and the Midpoint 500/345kV Second Transformer are listed in Table 3 below.

Table 3 **Asset Swap Costs**

Upgrade Project	Estimated Project Cost
Midpoint – Kinport 345kV Series Capacitor	$11,300,000
Midpoint 500/345kV Transformer Addition	$35,400,000

11. Federal Funding for B2H

The November 2021 Infrastructure Investment and Jobs Act ("IIJA") specified funding for transmission, for which Idaho Power may qualify. The IIJA includes $5 billion in direct funding, a $2.5 billion revolving loan in the Transmission Facilitation Program ("TFP"), and $3 billion in the Smart Grid Investment Matching Grant Program. Staff's Request for Company Reply Comments 22 requests an explanation why Idaho Power has not sought external funding for B2H.[95]

While the solicitation window for applicants to submit projects for IIJA grant money has not opened, the Company is monitoring the program and has responded to a DOE Request for Information ("RFI") in June 2022. As a requirement, the project applicant must demonstrate an eligible project is *unlikely to be constructed in as timely a manner or with as much transmission capacity* in the absence of TFP facilitation.[96] Because the B2H project has a negotiated term sheet, 80 percent of the available capacity is subscribed, and the partners are working toward finalizing associated agreements, it is not likely the B2H project would qualify for these funds.

[95] Staff's Comments at 24.
[96] U.S. Department of Energy, Notice of Intent and Request for Information regarding establishment of a Transmission Facilitation Program, 87 FR 29142, 29145 (May12, 2022), https://www.govinfo.gov/content/pkg/FR-2022-05-12/pdf/2022-10137.pdf.

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12. Access to Wholesale Markets

The 2021 IRP describes how capacity outside Idaho Power's transmission system has become congested, however Staff believes the Company does not provide a comprehensive analysis of how that congestion may be relieved due to new transmission projects planned outside the Company's balancing area.[97] Staff's Request for Company Reply Comments 23 asks for a list of transmission projects outside Idaho Power's balancing area that may provide new opportunities for firm transmission from market hubs to the Company's customers, most notably Greenlink.[98]

Figure 8 in Appendix D provides a comprehensive list of regional transmission projects. The table below lists the same regional transmission projects but with an added designation of whether each project may provide new opportunities for firm transmission from market hubs to Idaho Power.

Table 4 Regional Transmission Projects

Regional Transmission Projects	Idaho Power Access to Western Market Hub(s)?
B2H	Yes (Mid-C)
Gateway West	No
SWIP-North	Yes (Southern Market)
NVE Greenlink	Potentially (Southern Market via NVE System)
TransCanyon Cross-Tie	No
Gateway South	No
TransWest Express	No

The Company is not certain whether the Greenlink project will provide a new opportunity for firm transmission from the south. The current constraint is getting from the southern market hubs, across the One Nevada 500 kV line, and the NV Energy 345 kV system, to the Valmy substation and Idaho Power's capacity rights. If Greenlink is constructed, it is possible that a parallel path between Las Vegas and Reno could result in some transmission availability to NV

[97] Staff's Comments at 23-24.
[98] Staff's Comments at 24.

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Energy's connection with the Company. Idaho Power will continue to monitor transmission availability in Nevada and opportunities as NV Energy develops the projects.

The SWIP-N project would also potentially open new opportunities for the Company to access Southern Market hubs with firm transmission. The Company performed an opportunity evaluation to test whether Idaho Power customers would benefit from Idaho Power's involvement in the project. Based on the analysis the project appears to be worth further exploration. Idaho Power will perform a more detailed evaluation of SWIP-North in future IRPs.

E. Portfolio Modeling

1. <u>20-Year Limit to Costs</u>

Staff is investigating whether Idaho Power's use of 20 years of levelized costs in the IRP modeling is excluding any costs, thereby potentially skewing resource decisions or creating bias toward capital investments.[99] Staff is concerned that 20-year levelized costs do not adequately capture investment costs that occur beyond the 20-year planning horizon and, as such, might create a bias in favor of capital expenditures with long depreciation schedules against other resource alternatives.[100] Staff's Request for Company Reply Comments 24 and 25 ask the Company to explain how costs have been levelized into an annual number and how the 20-year constraint on costs improves Idaho Power's resource planning compared to including the full net present value ("NPV") of the lifecycle cost of each investment made during the 20-year planning horizon.[101]

Converting levelized costs into an annual number begins by first calculating the revenue requirement for each year of the asset's life, then calculating the present value of the revenue requirement over the life of the asset, and, finally, calculating the levelized payment. The levelized payment formula is as follows:

[99] Staff's Comments at 24.
[100] Staff's Comments at 24-25.
[101] Staff's Comments at 25.

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$$\text{Levelized Payment} = (r*NPV)/(1-(1+r)^{-n})$$

NPV: Net Present Value
r: discount rate
n: number of periods

Utilizing the levelized payment formula fairly accounts for the cost of projects with different asset lives. To consider only the NPV of an investment will not account for assets of differing lives. For example, consider two assets each with a Present Value of the Revenue Requirement ("PVRR") at $100 million. Asset 1 has a life of 10 years and Asset 2 has a life of 60 years. Over the 60 years of Asset 2, Asset 1 would have to be replaced 5 times. For simplicity's sake, assume that the PVRR for Asset 1 considering its replacement in years 11, 21, 31, 41, and 51 equals $350 million. Therefore, if only utilizing the PVRR, the additional 50 years of benefit from Asset 2 are ignored. The levelized payment method gets the cost to an annualized basis that can be compared across projects of different asset lives. The levelized payment for Asset 1 would be $14.3 million and the levelized payment for Asset 2 would be $7.2 million. The IRP uses the levelized annual payment for all years the resource has been selected, as this method gets the cost to an annualized basis that can be compared across projects of different asset lives and different time periods when the asset is selected and used.

2. Future Qualifying Facilities ("QF")

For resource planning, Idaho Power assumes that all projects with signed contracts will provide generation per their agreements with the Company but does not assume that any additional QFs will be developed during the planning period. Staff finds this to be an unreasonable assumption, particularly when the construction of B2H can be expected to increase opportunities for QFs.[102] Staff's Request for Company Reply Comments 26 asks the Company to comment on the possibility of modeling zero growth in QFs beyond signed contracts in the first four years and adding a forecast of future QF resources starting in the fifth year of the planning horizon.[103]

[102] Staff's Comments at 25.
[103] Staff's Comments at 25-26.

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The Company believes its QF forecast methodology for the 2021 IRP is both sound and justified and is the optimal process for future IRPs. A forecast for additional QFs, beyond those already contracted, would add unnecessary uncertainty to the process. By only analyzing highly probable QFs that have signed contracts, Idaho Power believes it is reasonably estimating a probable QF future without requiring speculation.

Further, the inclusion of speculative QF development in the IRP would create a long-term planning risk that could impair resource adequacy. Contrary to Staff's belief that "excluding QFs can have the effect of overestimating system resource needs," the inclusion of a forecast of additional QFs could actually hide system resource needs if PURPA developments do not occur as forecasted. And importantly, the Company's decision not to model additional forecasted QFs does not mean new QFs will not emerge but rather is based on the sound principle that long-term planning cannot be based on speculative decisions that are beyond the Company's control.

3. Resource Retirement

In the Company's IRP modeling, coal plants are the only existing resource considered for exit or retirement by AURORA. If a coal plant is selected for gas conversion, it is no longer a coal plant and is excluded from consideration for early exit or retirement. Staff believes this coal plant retirement/conversation logic results in unequal treatment of resources and all resources should be considered for retirement during the 20-year planning horizon.[104] Further, Staff has concerns about the consistency of how decommissioning costs are considered.[105]

Staff's Request for Company Reply Comments 27 asks the Company to explain how the limitation on resource exit/retirement selection improves Idaho Power's resource planning.[106] Idaho Power believes that the limits on resources that can be retired/exited are reasonable because the model should, to the extent possible, reflect actual build and operation behavior—

[104] Staff's Comments at 26.
[105] Staff's Comments at 26.
[106] Staff's Comments at 26.

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that is, allowing the model to retire a 30-year asset after 10 years of operation runs counter to actual energy system investment and operations. Assets are intentionally and specifically modeled to be used for their full expected lifetime—except in notable circumstances, such as the realized benefit of early coal exits/retirements.

Further, and because this suggestion is far from the norm in long-term modeling, Idaho Power does not have reasonable estimates of the retirement costs associated with non-coal resources because they have not been studied and scrutinized at the level necessary to model their costs. Without these values, the model is unable to accurately calculate the optimal retirement decisions for these units. However, as this question is of particular interest to Staff, the Company plans to consider this issue further in the 2023 IRP.

Staff's Request for Company Reply Comments 28 asks the Company to describe the decommissioning costs Idaho Power is seeing in bids for the Company's current RFPs.[107] The bids received in the Company's current RFP for 2024 and 2025 have not included decommissioning cost estimates. During the RFP process to acquire resources for 2023, the Company discussed decommissioning costs with the developers and manufacturers during the evaluation phase. The amount of lithium and other valuable metals remaining in the batteries at end-of-life is estimated to be substantial. It is anticipated that a mature market will exist to recycle these metals. In some scenarios, recyclers may pay Idaho Power to take the batteries and recycle the lithium and other valuable metals remaining in the batteries. Some bidders indicated they would take the batteries back in 20 years and require only shipping to their facilities (some in the United States and some in Asia). Based on these discussions with developers as summarized above, the Company did not require decommissioning costs as part of the estimates.

[107] Staff's Comments at 26.

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4. Reliability

Staff notes that only one of the Company's portfolios in the 2021 IRP meets the reliability threshold LOLE of .05 days per year, and it is not the Preferred Portfolio.[108] Staff finds this unusual for a utility to consider portfolios that have higher LOLEs than the Company's minimum standard.[109] Staff's Request for Company Reply Comments 29 asks the Company to explain why meeting Idaho Power's reliability standard was a challenge in some portfolios.[110]

The ELCC of VERs is calculated using the last-in ELCC method, where the ELCC of the last resource added to the system is calculated. When determining the Planning Reserve Margin ("PRM"), Idaho Power determined the ELCC of both existing and future resources. The ELCC calculation of future resources is dependent on the mix of resources already on the system. When creating a portfolio, AURORA looks at the highest load hour, each resource's ELCC, and the given PRM to build a reliable portfolio. As AURORA selects resources, especially in the outer years of the planning horizon, the ELCC values initially calculated might have changed given the resources already selected in the portfolio, creating a discrepancy between the PRM and the LOLE. The ELCC of each resource slightly changes with every resource addition in a portfolio. In order to align the PRM with the LOLE, it would be necessary to re-calculate every resource's ELCC with each new resource addition. This approach was considered, but ultimately not selected due to software and model runtime constraints.

In lieu of that approach, Idaho Power verified that each of the top portfolios met the reliability threshold by running each of those portfolios through the LOLE tool. If there was a year in a given portfolio that did not meet the reliability threshold, a resource was added to the portfolio until every year in the planning horizon met the reliability threshold. This two-step verification

[108] Staff's Comments at 26.
[109] Staff's Comments at 26-27.
[110] Staff's Comments at 27.

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process ensured each portfolio met the reliability criteria. This approach was shared with the IRPAC on November 18, 2021, to seek feedback and alignment.[111]

Staff reasons that the resource cost proxy added to the portfolios that do not meet the LOLE of .05 days does not cover the full cost of meeting this unserved load with a natural gas peaker plant.[112] Staff's Request for Company Reply Comments 30 asks the Company to explain how it plans to avoid a loss of load in 2037 with the Preferred Portfolio and how the expected cost of this solution differs from the capital cost of a simple cycle combustion turbine ("SCCT") plant.[113]

The Company plans to avoid a loss of load event in 2037 by continuing to monitor the LOLE of its resource stack and ensuring that whatever resources are added through the RFP process, the overall reliability standard of 0.05 days per year is maintained. The Company expects the eventual cost to maintain the reliability standard to differ from the generator costs added to the portfolios. For the 2021 IRP, a SCCT cost was added because it is a flexible resource with a high ELCC that allowed for a quick and simple comparison between portfolios; use of a SCCT as a proxy is not intended to be prescriptive and does not imply that the Company would build a gas plant in 2037.

In terms of portfolio performance and resource needs, the IRP Action Plan window receives the highest scrutiny compared to years toward the end of the IRP planning horizon. This is appropriate because the degree of certainty in a Preferred Portfolio diminishes over the planning horizon. Actual resource acquisition through RFP processes may differ from the resources identified in the Preferred Portfolio, forecasts will be adjusted, new programs and standards may materialize, and system needs identified in outer years (including 2037) will be updated as a result.

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[111] Idaho Power, LOLE Portfolio Analysis (Nov. 18, 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/2021_11_18_LOLE_IRPAC.pdf.
[112] Staff's Comments at 27.
[113] Staff's Comments at 27.

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F. Climate Risk Report, Emissions and Clean Energy Goal

Staff states that an IRP also serves as a public document that stakeholders and policymakers can access to learn about a Company's greenhouse gas ("GHG") emissions.[114] For this reason, Staff states that it carefully reviews the accuracy of emissions projections and the efficacy of the Company's zero emissions by 2045 goal.[115]

1. Risk Identification and Management

Staff Request for Company Reply Comments 31 asks Idaho Power to describe the climate policy risks for which the Company plans and to include any details regarding the nature of its policy risk planning, including, but not limited to, those regarding modifications to accounting and public company reporting requirements.[116]

For the first time in an IRP, Idaho Power's 2021 IRP included a dedicated chapter on climate change (see Section 3 of the 2021 IRP). That chapter includes a robust discussion of the Company's climate change mitigation efforts, carbon emissions profile, and identification and discussion of climate change risks that are considered within and outside of the Company's IRP. The Company notes in the IRP that:

> Climate change-specific risks are an evolving category that includes, but may not be limited to, changes in customer usage and hydro generation due to changing weather conditions and severe weather events. Wildfire is another category of risk that is influenced, although not solely driven by, climate change. In Idaho Power's service area, climate-related risks are evaluated in light of potential for storm severity, lightning, droughts, heat waves, fires, floods, and snow loading. Policy-oriented risk with respect to climate change can be understood as climate-oriented laws, rules, and regulations that could impact Idaho Power operations and planned capital expenditure.[117]

Identified risks are addressed in detail within the Climate Change section of the IRP, pages 31-34. Regarding public company reporting requirements, the Company does not perceive such

[114] Staff's Comments at 28.
[115] Staff's Comments at 28.
[116] Staff's Comments at 28.
[117] 2021 IRP at 30-31.

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reporting requirements—or any expanded reporting requirements in the future—as risks but rather as necessary components of various compliance documents.

2. Historical Emissions

The 2021 IRP presents Idaho Power's historic emissions, which show a general trend of reduced emission intensity and total emissions since 2003; however, since 2017, carbon dioxide ("CO_2") emissions intensity increased from 633 to 837 lbs/MWh CO_2 and total emissions increased from 4,323,146 to 5,355,098 tons of CO_2. Staff's Request for Company Reply Comments 32 and 33 ask the Company to describe how market conditions led to a recent increase in emission intensity and how Idaho Power intends to address emission intensity from low water supply and market conditions.[118]

Low hydro availability is the primary market condition that has led to overall increased emissions intensity in recent years. In 2021, other market conditions that increased emissions intensity include elevated peak load conditions such as those that occurred late June 2021 when much of the Pacific Northwest was inundated by an extended heat event. Transmission system congestion limited the Company from accessing the Mid-C market and required greater dispatch of thermal units. Solar attenuation also occurred due to wildfire smoke.

The Company believes that by implementing the Action Plan of the 2021 IRP's Preferred Portfolio, the variability of emissions due to water supply and market conditions will decrease. The Preferred Portfolio calls for exiting all coal resources by 2028, adding 700 MW of wind, 1,405 MW of solar, 1,685 MW of storage, 100 MW of DR (in addition to the 300 MW in existing DR), and 440 MW of energy efficiency resources through 2040.[119] All these resource decisions reduce emissions intensity and create a diverse portfolio of clean resources that will allow the Company to weather a variety of market conditions.

[118] Staff's Comments at 29.
[119] 2021 IRP at 4.

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3. 100 percent Clean by 2035 Scenario Emissions and LOLE

In the 2021 IRP, the Company generated a 100 percent Clean by 2035 portfolio to analyze the feasibility of an accelerated transition to decarbonization. The Company explained that it was difficult to model a portfolio designed to meet this emission target while maintaining reliability. Staff's Request for Company Reply Comments 34 asks the Company to provide the LOLE for the 100 percent Clean by 2035 portfolio.[120] Due to the extensive time required to develop individual LOLE analyses, the Company conducted LOLE assessments only for portfolios that were in contention for the Preferred Portfolio and not for all future scenarios. Also, the 100 percent Clean by 2035 scenario was performed as a LTCE run only. The purpose of the run was to provide a high-level comparison of the resources in that scenario compared to the Preferred Portfolio.[121] The Company anticipates further developments on this scenario will be part of the 2023 IRP given modeling software advances.

4. Market Purchases and Emissions

Staff believes the Company's forecast of emissions is lacking because it does not include emissions from market purchases.[122] Staff finds that the inclusion of an emissions estimate for market purchases consistent with the BPA emissions rate for unspecified market power would improve the emissions forecast and make it more comparable to that of other utilities in the region that report emissions consistent with Oregon House Bill 2021 ("HB 2021")—notably, Idaho Power is exempt from HB 2021.[123] Staff's Request for Company Reply Comments 35 asks the Company to provide an updated emission forecast for planning conditions that includes emissions from market purchases, one with the standard BPA unspecified mix method and another with Idaho Power's most reasonable estimate of the future emissions intensity of market purchases.[124]

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[120] Staff's Comments at 30.
[121] *See* 2021 IRP at 158.
[122] Staff's Comments at 30.
[123] Staff's Comments at 30.
[124] Staff's Comments at 30.

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Following a discussion with Staff on June 16, 2022, as noted in Staff's comments,[125] the Company performed the detailed calculation, which involved the following steps:

1. Determining the average zonal emissions rate for every zone from which power enters Idaho Power's zone on a monthly basis;
2. Applying that emissions rate to the corresponding monthly power flows into Idaho Power's zone; and
3. Subtracting the emissions for sales out of Idaho Power's zone using the same logic.

Based on the detailed calculation method described above, Table 5 displays the adjustments to the emissions data for the 2021 IRP Preferred Portfolio.

Table 5 Preferred Portfolio CO_2 (short tons) AURORA Zonal Emissions Rate

Year	Total Generation Emissions	Purchase Emissions	Sale Emissions	Net Purchase Emissions	Generation Plus Net Purchase Emissions
2021	3,146,734	15,201	-95,518	-80,317	3,066,416
2022	3,464,248	18,403	-106,252	-87,849	3,376,399
2023	3,133,471	27,802	-69,645	-41,843	3,091,627
2024	2,428,049	9,610	-118,255	-108,645	2,319,404
2025	2,304,014	13,415	-98,709	-85,294	2,218,719
2026	2,014,136	18,383	-67,136	-48,753	1,965,382
2027	2,025,337	18,390	-59,761	-41,371	1,983,966
2028	2,111,398	22,486	-52,337	-29,851	2,081,547
2029	1,748,562	24,028	-28,703	-4,676	1,743,887
2030	1,725,706	25,142	-21,628	3,515	1,729,221
2031	1,787,393	30,488	-16,177	14,311	1,801,704
2032	1,831,248	31,351	-17,131	14,221	1,845,469
2033	1,905,600	40,218	-12,376	27,842	1,933,442
2034	1,889,374	41,332	-14,143	27,189	1,916,563
2035	1,783,130	45,737	-13,669	32,069	1,815,199
2036	1,787,069	53,683	-12,509	41,174	1,828,243
2037	1,809,568	33,396	-10,503	22,893	1,832,460
2038	1,839,524	32,778	-11,231	21,547	1,861,071
2039	1,869,889	30,929	-10,423	20,506	1,890,395
2040	1,861,797	31,798	-10,252	21,547	1,883,344

[125] Staff's Comments at 30.

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The Company has not used the BPA rate but has instead applied the Oregon Department of Environmental Quality ("DEQ") default rate for historical unspecified purchases of 0.428 MT CO_2e/MWh to projected market purchases. A cursory search for BPA's unspecified emissions amount (both through BPA's website and general search tools) does not describe the methodology or reasoning used by BPA for the values that were developed. Without further details, the Company is unable to recreate the BPA method, which is why the Oregon DEQ value was applied. The results of the calculation using the Oregon DEQ value are in Table 6 below. Because the Oregon DEQ value only applies to market purchases, an emissions factor was not applied to sale emissions, thus that column contains only zeroes.

Table 6 Preferred Portfolio CO_2 (short tons) Oregon DEQ Calculation

Year	IPC Total Generation Emissions	Purchase Emissions	Sale Emissions	Net Purchase Emissions	Generation Plus Net Purchase Emissions
2021	3,146,734	574,196	0	574,196	3,720,929
2022	3,464,248	556,748	0	556,748	4,020,996
2023	3,133,471	527,994	0	527,994	3,661,465
2024	2,428,049	187,336	0	187,336	2,615,385
2025	2,304,014	271,527	0	271,527	2,575,541
2026	2,014,136	254,453	0	254,453	2,268,589
2027	2,025,337	315,823	0	315,823	2,341,161
2028	2,111,398	371,072	0	371,072	2,482,470
2029	1,748,562	433,731	0	433,731	2,182,293
2030	1,725,706	614,037	0	614,037	2,339,743
2031	1,787,393	736,500	0	736,500	2,523,893
2032	1,831,248	720,704	0	720,704	2,551,952
2033	1,905,600	910,171	0	910,171	2,815,771
2034	1,889,374	907,059	0	907,059	2,796,433
2035	1,783,130	1,047,036	0	1,047,036	2,830,167
2036	1,787,069	1,149,225	0	1,149,225	2,936,294
2037	1,809,568	1,397,759	0	1,397,759	3,207,326
2038	1,839,524	1,405,666	0	1,405,666	3,245,190
2039	1,869,889	1,478,062	0	1,478,062	3,347,951
2040	1,861,797	1,701,905	0	1,701,905	3,563,702

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Although the Company provided two methods to approximate the emissions rate for market purchases, the Company disagrees with the default emissions rate calculation. The Company's service area is located along a major transmission corridor between the Pacific Northwest and the Intermountain West. Power purchases can be sourced from many regions with diverse resource portfolios. To apply a flat emissions rate to wholesale purchases would not reflect locational or seasonal variations in emissions rates reflective of different resources being leveraged. A flat emission rate also does not reflect the expected market transition to clean energy, which is rapidly occurring as utilities throughout the WECC move toward decarbonization. Due to the default emission rate calculation's lack of specificity as to where and when purchases originate, the default emissions rate fails to capture that modeled purchases largely originate from zones with abundant clean hydro power.

Further, counting only emissions associated with purchases means the emissions associated with the purchase is counted twice—once in the selling utility's emissions and again in the purchasing utility's emissions because sales are not subtracted based on the purchase-only methodology.

In the Company's estimation, evaluating market emissions on a net basis (the sum of emissions associated with purchases minus those associated with sales) is a more reasonable method of evaluating emissions if market transactions must be considered.

5. <u>2021 Emissions Forecast</u>

Staff's Request for Company Reply Comments 36 requests the Company provide an emission forecast for 2021 using the 2021 IRP's conditions that reflect events observed that year, such as low hydro conditions.[126] Without loss of generality the Company is unable to perform the requested analysis based on the 2021 hydro conditions. Portfolio emissions are influenced by a myriad of factors over vast and diverse geographies across the West and for which accurate

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[126] Staff's Comments at 30.

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historical data is not available to the Company. Instead, the portfolio emissions generated by AURORA are based on typical or planning conditions for which more information is available. Because a utility's IRP model is not intended to perfectly capture daily operations, the Company expects that actual emissions will differ year to year from AURORA's modeled emissions.

6. Communicating the Clean Energy Goal

Staff encourages the Company to make its external messaging on emissions consistent with Idaho Power's actual resource planning.[127] Staff states the Company claims to have a goal to provide 100 percent clean energy by 2045, yet the Company's Preferred Portfolio is not expected reach this goal by 2045, and it is relatively far from doing so.[128] The Preferred Portfolio reduces emissions only 41 percent from 2021 to 2040. Staff's Request for Company Reply Comments 37 asks the Company to explain what probability the Company expects to meet its goal of reaching 100 percent clean energy by 2045.[129]

As the Company has expressed to Staff on prior occasions, the Company's goal of reaching 100 percent clean energy by 2045 was set—and remains—with an understanding that technologies will advance, and the price of clean energy resources will become more competitive over time. These changes are occurring rapidly, as evidenced by the resources selected in the 2019 IRP compared to the 2021 IRP. Most of these clean resource changes occur quickly; B2H is scheduled to increase access to clean resources in 2026, the last coal exit appears in the plan in year 2028, and large amounts of clean resources—including solar, wind, storage, demand response, and energy efficiency—are selected within the Action Plan Window (2021-2027). While no probabilities have been or can be calculated, the Company is advancing towards meeting this goal in the early plan years. The Company's position remains that these advances will continue, and the goal will be met while maintaining a focus on low cost and reliable service.

[127] Staff's Comments at 30.
[128] Staff's Comments at 30.
[129] Staff's Comments at 30-31.

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IV. REC'S COMMENTS

REC's Opening Comments provide general support for Idaho Power's continued planning assumption that 100 percent of non-wind QFs will renew after contract expiration.[130] Further, for this filing, REC is not opposed to Idaho Power's planning assumption that 25 percent of wind QFs will renew after contract expiration but recommends that Idaho Power revisit this assumption in the 2023 IRP.[131] Therefore, REC requests the Commission acknowledge these QF renewal planning assumptions in this IRP and direct Idaho Power to revisit the wind QF renewal assumption during the next IRP.[132]

Idaho Power appreciates RECs general support and will re-visit the topic of QF renewal assumptions in the next IRP.

V. CUB'S COMMENTS

CUB's Opening Comments note the major and rapid shift in the Company's load and resource balance from resource sufficient to resource deficient status. CUB discusses some of the factors that contributed to the near-term capacity deficiencies and the Company's readiness in bringing significant quantities of renewables on its system as identified in the Preferred Portfolio.[133]

VI. TRANSMISSION

1. Transmission Assumptions: 2019 IRP vs 2021 IRP

CUB states that "one of the driving factors behind Idaho Power's imminent capacity deficiency is a loss in transmission availability" and summarizes the various events that took place during 2021 that forced the Company to modify its transmission assumptions.[134] CUB believes

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[130] The Renewable Energy Coalition's Opening Comments at 2 (July 7, 2022) [hereinafter, "REC's Comments"].
[131] REC's Comments at 2-4.
[132] REC's Comments at 1, 4.
[133] Opening Comments of the Oregon Citizens' Utility Board at 1-2 (July 7, 2022) [hereinafter, "CUB's Comments].
[134] CUB's Comments at 2-3.

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the Company did not properly show the changes made from the previous IRP that accounts for the 200 MW shortfall and requests the Company identify specific sources of congestion and the resulting loss in transmission capacity that led to a change in assumptions in this IRP.[135]

For the 2021 IRP, the Company adjusted how it determines transmission availability by requiring a Company reservation on third-party transmission systems between market hubs and Idaho Power, in addition to the set-aside reservation of internal Idaho Power controlled transmission to be included in the load and resource balance. The transmission connections and the changes between the 2019 IRP and 2021 IRP are shown in Table 7 and discussed in more detail below.

Table 7 Transmission Capacity Assumptions: 2019 IRP vs 2021 IRP

Transmission Connection	Market	2nd Amended 2019 IRP Capacity Available for Market Purchases (2023)	2021 IRP Capacity Available for Market Purchases (2023)
Idaho-Northwest (Path 14)	Mid-C Hub	287 MW	330 MW
Idaho-Montana (Path 18)	Mid-C Hub	77 MW	0 MW
Idaho-Nevada (Path 16)	Southern Market Hubs	229 MW (with Valmy Unit 2 in-service)	0 MW
Idaho-Utah (Path 20)	Southern Market Hubs	0 MW	50 MW
CBM (Path 14)	Mid-C Hub	330 MW	330 MW
Total		923 MW	710 MW

Path 14 and Path 18 provide access to the Mid-C hub in the Northwest. There was a total 34 MW reduction in capacity available for market purchases for Paths 14 and 18 in the 2021 IRP compared to the 2019 IRP ((330 MW – 287 MW) + (0 MW – 77 MW) + (330 MW – 330 MW) = -34 MW). The increase in available capacity at Idaho-Northwest was due to the updated network customer load forecast. The reduction in available capacity at Idaho-Montana was due to the lack

[135] CUB's Comments at 3-4.

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of available third-party firm capacity. Between the 2019 IRP and 2021 IRP, there was no change in available capacity associated with CBM.

The key change in available capacity between the 2019 IRP and 2021 IRP was the Idaho-Nevada transmission capacity (i.e., Path 16). In the 2019 IRP the Company assumed that generation from North Valmy could be replaced by market purchases from southern market hubs. The Valmy Unit 2 Exit Analysis performed by the Company early in 2021 tested this assumption and confirmed that firm transmission across the NV Energy system to southern market hubs was not available—thus, the 229 MW reduction in available capacity for market purchases for that pathway in the 2021 IRP compared to the 2019 IRP. The Valmy to Midpoint 345 kV line has a South-to-North rating of 360 MW, of which approximately 130 MW is reserved for North Valmy Unit 2. The remaining approximate 229 MW of transmission capacity on the Valmy – Midpoint 345 kV line was removed from the available transmission capacity counting toward peak.

For Path 20, an existing 50 MW reservation from Red Butte to Borah across the PacifiCorp East system was not included in the 2019 IRP assumptions. This reservation provides the Company access to the southern market hub at Mead. Including this reserved capacity in the 2021 IRP offsets 50 MW of the 229 MW of reduced southern market capacity.

2. <u>Transmission Assumptions: Availability and Capacity Benefit Margin ("CBM")</u>

Of the 710 MW of available transmission, 330 MW is CBM and CUB states that there is no further information on what ensures this emergency transmission availability.[136] CUB requests the Company explain the rationale behind the current transmission availability assumption and also provide an explanation of how the Company plans to utilize emergency transmission resources.[137]

The Company provided the following information related to CBM on Page 14 of Appendix D:

[136] CUB's Comments at 4.
[137] CUB's Comments at 4.

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> CBM is transmission capacity Idaho Power sets aside on the company's transmission system, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, in this case the Pacific Northwest. An energy emergency must be declared by Idaho Power before the CBM transmission capacity becomes firm. To access the market, transmission beyond Idaho Power on third party providers must be acquired. The company anticipates this third-party transmission will be available during an energy emergency event. Idaho Power includes the 330 MW of emergency transmission (CBM) toward meeting a 15.5% planning margin. In future IRP's, Idaho Power will continue to evaluate how CBM applies in the context of Idaho Power's Load and Resource Balance, specifically if the company is a member of a regional resource adequacy program.[138]

If the Company is in an energy emergency and needs to utilize CBM, it will likely eliminate (the typical vernacular is "cut") non-firm West-to-East Idaho to Northwest path schedules of other entities and, in doing so, free up transmission between the Mid-C market hub and Idaho Power's transmission system. An example of path schedules: if there is a third-party power schedule from Mid-C to Nevada that is flowing across Idaho Power there are likely three legs of transmission associated with that schedule: (1) Mid-C to Walla Walla (across PacifiCorp hypothetically), (2) Walla Walla to Midpoint (across Idaho Power), and (3) Midpoint to Reno (across NV Energy). The Walla Walla to Midpoint schedule across the Company will almost certainly be non-firm. If the Company goes into an energy emergency and needs to utilize CBM, this non-firm schedule will be cut. In cutting this schedule, the Mid-C to Walla Walla, Walla Walla to Midpoint, and Midpoint to Reno scheduling paths will all likely become available. Given CBM, the Company has the right to place a firm schedule on the Walla Walla to Midpoint load segment (replacing the Midpoint point-of-receipt with another load service point), and the expectation is that the Mid-C to Walla Walla segment will now be available as well. There is risk associated with assuming third-party transmission will be available for CBM and the Company expects the future Western Power Pool's

[138] 2021 IRP, App. D at 14 (Feb. 16, 2022).

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Western Resource Adequacy Program ("WRAP") will provide an opportunity to make adjustments to IRP-related CBM assumptions in the 2023 IRP.

3. Transmission Assumptions: The WRAP

CUB would appreciate the Company detailing how participation in the WRAP is likely to affect both its anticipated capacity shortfall and the transmission needs it points to.[139] The Company is currently waiting for the program to publish final PRMs, qualifying capacity contributions for resources, and other program parameters. WRAP participation is expected to reduce the Company's planning margin requirement and preliminary PRMs indicate substantial reductions. The WRAP is designed to ensure liquidity within the footprint by providing region-wide coordination of resources at least five months prior to the operating season; this has the appearance of impacting how Idaho Power views CBM. CBM will continue to be a valuable component of reliability but will not be considered as a resource in the WRAP Forward Showing window. Idaho Power currently considers CBM as a resource for long-term planning but does not consider CBM as a resource for Summer Readiness Load and Resource planning. Idaho Power expects to adjust its treatment of CBM as a resource for long-term planning to ensure successful participation in the program aligning long-term and short-term planning processes. The Company expects that participation in the WRAP will result in a net increase in the need to commit additional resources in the Forward Showing window but will not decrease Idaho Power's transmission needs. Transmission is essential to sharing load and leveraging resource diversity. Identifying, committing, and coordinating resources across a larger footprint is essential to ensuring reliability and market liquidity.

B. WRAP Participation and DR

CUB has many questions for the Company as the WRAP is discussing using ELCC or "operational testing and historical performance" for resource capacity accreditation for wind and

[139] CUB's Comments at 5.

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solar resources in the Forward Showing Programs ("FSP") and seeks to understand how it will impact the Company's ELCC for DR.[140]

While it is early to analyze a program that is still being structured, Idaho Power will carefully review the resource accreditation for energy resources and whether it makes sense to use them in future IRPs. It is important to point out that regional values are not always representative of local systems. The Company commits to share with IRPAC details of the WRAP as they become available.

Regarding the ELCC of the Company's DR programs, when the DR programs were designed, the hours of highest risk were aligned with the hours of highest load given the small penetration of VERs, at the time. With the recent increase of VER penetration, the hours of highest risk are no longer necessarily aligning with the hours of highest load. This was the main reason for the implementation of the ELCC methodology in the 2021 IRP. The use of the ELCC methodology quantifies the reduction of the DR programs' effectiveness as the system buildout changes.

C. Load Forecast

Idaho Power has explained that part of its near-term capacity needs are due to "higher than expected load growth." CUB requests an account of model improvements that Idaho Power has planned to improve its peak load forecast model.[141]

1. <u>Load Forecast: Neural Network</u>

CUB asks the Company to explain what modeling improvements the neural network has brought to the 2021 IRP analysis and how it is an improvement over the linear regression model.[142] It is important to note that the process of Ordinary Least Squares ("OLS") regressions for monthly peak forecasting and monthly energy sales currently is used to produce the results

140 CUB's Comments at 6.
141 CUB's Comments at 6.
142 CUB's Comments at 6-7.

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used in resource planning efforts. These processes use the Company's well-established and acknowledged peak and load framework. The hourly model shapes the monthly energy and demand by defining the date and hour over the course of the planning period and is governed by those monthly model outputs and does not override those results. This process is extremely beneficial as it allows the Company to understand, from a forecasting perspective, the class contributors to the overall system peak.

The Company appreciates that introduction of the neural network model adds complexity. As such, the Company has taken steps to develop a process that sets the targets of the neural net using traditional OLS regression and only relies on the neural net to shape the hourly system to those limits.

2. Load Forecast: Unusual Conditions

CUB requests the Company provide a narrative explanation of how the neural network model accounts for unusual conditions that could impact hourly electricity load forecast in the long term.[143] As noted above, the Company does not rely on the output of a neural network to inform the ultimate system peak but rather the shaping of the system to get to that point.

Outside of large customer loads over 1 MW, weather is the primary factor influencing system shaping. To shape the system, the neural network model leverages the Levenberg-Marquardt process, commonly used to solve non-linear least squares problems. The Levenberg–Marquardt process blends the steepest descent method and Gauss-Newton process. The basic idea of Levenberg–Marquardt is that it performs a combined training process. Around the area with complex curvature, the Levenberg–Marquardt switches to the steepest descent process, until the local curvature can make a quadratic approximation, at which point it approximately becomes the Gauss–Newton. This process can speed up the convergence significantly. This process is well-suited to handle the non-linear nature of the electric weather response. As such, it would be

[143] CUB's Comments at 7.

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expected, outside large load requests, that future surprises in load variation do not cause instability using this method.

3. Load Forecast: Cryptocurrency Customers

CUB notes Idaho Power's recently approved Idaho Rate Schedule 20 and asks for an explanation from the Company regarding how this schedule impacts its anticipated capacity shortfall.[144] The answer is that it does not. It is true that the Company has received an increase in inquiries from cryptocurrency mining operations over the last year, however, the Company does not include speculative load into the load forecast. The purpose of Idaho Rate Schedule 20 was merely to have a set pricing structure for cryptocurrency customers, if and when they arise.

D. Preferred Portfolio

Idaho Power's 2021 IRP Preferred Portfolio includes large amounts of renewable resources throughout the planning period. CUB believes these changes are progressive and welcomes them. At the same time, CUB is concerned about the Company's ability to support these significant quantities of VERs with adequate transmission and demand side measures that are necessary to reliably serve customers.[145]

1. Transmission Assumptions

CUB describes the possible need for Gateway West (given all the renewable resources in the Preferred Portfolio) and requests a scenario in which transmission capacity gains from both Bridger and Valmy exits together are not realized and further requests Idaho Power to provide updates on the expected construction timeline of segment 8 of Gateway West.[146] The Company recognizes and shares CUB's concern about ensuring adequate transmission capacity as the power system moves toward higher VER levels. While Gateway West was not selected in the Preferred Portfolio, it was selected in a number of runner-up portfolios. In the next IRP cycle,

[144] CUB's Comments at 8.
[145] CUB's Comments at 8-9.
[146] CUB's Comments at 10.

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differing exit scenarios for the Bridger units will continue to be studied along with triggers for Gateway West segments. These segments add required transmission capacity to support new resources across Idaho Power's system. Idaho Power does not have a firm timeline for segment 8 of Gateway West, as the transmission need is driven by resource procurement. However, the Company anticipates the line could be constructed relatively quickly once it is triggered by transmission capacity needs because much of the federal permitting for siting the line has already been completed.

2. Existing DR Assumptions

CUB requests the Company explain clearly how it used decreased participation or enrollment to revise assumptions about existing DR capacity.[147] CUB suggests that Idaho Power keep monitoring program contribution toward its peak capacity needs in the months of July and August and provide an update to the Commission.[148] As a point of clarification, Idaho Power did not use decreased participation or enrollment to revise assumptions about existing DR capacity. Rather, the Company used information from customers and knowledge of customers' systems and processes to estimate potential reduced participation due to modified program parameters. The modified parameters were needed to increase DR program effectiveness in the future. Idaho Power will evaluate its DR program after the 2022 season and update assumptions, as necessary, in the 2023 IRP.

3. Future DR Assumptions

As more renewables are brought onto the system, CUB believes that there should be a holistic approach to DR and that there is value in modeling price and behavior-based demand side programs as competing resources along with direct load control programs.[149] Idaho Power agrees that a holistic approach should be taken in modeling both traditional DR programs as well

[147] CUB's Comments at 11.
[148] CUB's Comments at 11.
[149] CUB's Comments at 12-13.

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as pricing programs and is including pricing programs as part of the current DR potential study that will inform the 2023 IRP.

4. Hells Canyon Complex ("HCC") Relicensing

CUB believes additional analysis is needed around the HCC as the Company makes investments in additional renewable resources to meet its resource needs and its clean energy goals.[150] CUB questions whether the new resource strategy will lessen the dependence on HCC.[151] Additionally, CUB asks whether customers may benefit from diverting Company resources from relicensing efforts to more productive areas.[152]

The renewable resources in the 2021 IRP are heavily dependent on the continued operations of Idaho Power's robust and low-cost hydro system. The flexibility and reliability of the HCC is key to the integration of intermittent wind and solar resources. Beyond the significant power that the HCC can produce reliably during the night or calm wind conditions, it also provides significant ancillary services including regulating reserves. The Company's modeling indicates that, as more renewables are integrated onto the system and as the Company moves forward with coal unit exits, dependence on the HCC to provide regulating reserves will nearly double over the planning horizon.

Given the size—both in terms of energy and reliable capacity—of the HCC, and the HCC's ability to provide regulating reserves that are crucial to the integration of renewables, there is no simple replacement for the HCC. The Company's most recent analysis indicated that the most likely replacement for the HCC is a combination of simple cycle and combined cycle natural gas turbines. The capital investment, ongoing operations and maintenance ("O&M") expenses and fueling costs of the replacement natural gas generators would be more expensive than the relicensing and continued operations of the HCC. If gas generation was the replacement

[150] CUB's Comments at 14.
[151] CUB's Comments at 14.
[152] CUB's Comments at 14-15.

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resource, it would make it difficult to achieve the Company's 100-Percent Clean Energy by 2045 goal. Therefore, the Company believes that the use of Company resources in the relicensing effort of the HCC is a prudent investment and resource strategy.

VII. RENEWABLE NORTHWEST'S COMMENTS

Renewable Northwest's Opening Comments offer general support for Idaho Power's planning and portfolio modeling framework. Renewable Northwest notes the 2021 IRP process was more inclusive of and receptive to stakeholder feedback.[153] Renewable Northwest 's Opening Comments focus on clarification and recommendations related to the Company's reliability threshold, climate change, and supply-side resources.

A. Reliability Threshold

Renewable Northwest is encouraged to see that the Company updated and expanded the contribution to peak calculations using the ELCC methodology.[154] However, noting that Renewable Northwest does not have a preference on a specific reliability threshold, clarification is needed that the 0.05 days per year threshold is different from the NWPCC's 5 percent Loss of Load Probability ("LOLP").[155] Renewable Northwest recommends the Company work with the NWPCC and the Resource Adequacy Advisory Committee ("RAAC") to ensure that correct definitions and methodologies are being used to conduct resource adequacy assessments.[156] The Company has reviewed its LOLE calculation methodology compared to the NWPCC LOLP methodology, and does see the results between the two as directly comparable, although with different calculation approaches. The Company appreciates Renewable Northwest's feedback and will continue to engage with Renewable Northwest, the NWPCC, and the RAAC to ensure

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[153] Renewable Northwest's Initial Comments at 1 (July 7, 2022) [hereinafter, "Renewable Northwest's Comments"].
[154] Renewable Northwest's Comments at 2.
[155] Renewable Northwest's Comments at 2.
[156] Renewable Northwest's Comments at 2-3.

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that correct definitions and methodologies are being used to conduct resource adequacy assessments.

B. Climate Change

Renewable Northwest appreciates Idaho Power's efforts to conduct additional scenarios and would like to encourage Idaho Power to use downscaled climate-adjusted models in the baseline scenarios instead of consideration as an additional scenario.[157] Citing climate change projections in the NWPCC 2021 Power Plan, Renewable Northwest recommends Idaho Power work with NWPCC to develop particular datasets for temperature and stream flow conditions that reflect the current reality in the baseline for hydropower generation rather than an additional climate change scenario.[158]

Idaho Power appreciates Renewable Northwest's acknowledgement of the hydropower modeling work conducted to date. Idaho Power strives to conduct robust and informative hydropower modeling for each IRP cycle. There are a number of considerations that bear mentioning regarding application of downscaled Global Climate Model ("GCM") forcings to hydrologic response, reservoir regulation, consumptive demand, and, ultimately, hydropower generation modeling. Idaho Power also notes that activities outside of climate change, namely weather modification and water management decisions, impact hydropower generation in a significant way. These topics are addressed below.

The elements described below summarize why the Company believes its hydropower modeling is robust and comprehensive in the 2021 IRP. The concept of what should represent the "current reality" baseline is relatively complex. The selection of a General Circulation Model ("GCM"), relative concentration pathway ("RCP") scenario, spatial downscaling method, and hydrologic model all influence the results. As the NWPCC 2021 Power Plan acknowledged, only three out of 19 climate scenarios available from the Risk Management Joint Operating Committee

[157] Renewable Northwest's Comments at 3.
[158] Renewable Northwest's Comments at 3.

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("RMJOC") study were used to evaluate potential temperature, precipitation, and streamflow responses.[159] Idaho Power recognizes that certain GCMs, downscaling, and hydrologic models can demonstrate better performance than other model combinations in the observed historical period, but ultimately the current modeling state is well informed by the use of recent historical hydrologic conditions, which themselves are beginning to reflect changes in climate that have occurred over the past several decades.

Separating climate change-induced natural flow shifts from regulated flow changes is important and is particularly of interest for Idaho Power based on the position of the hydropower system downstream from significant reservoir regulation, irrigation demand, and other water management activities. While many climate change and hydrologic models generally agree with increasing unregulated winter flows and decreasing summer flows, these unregulated flow changes then need to be regulated through upstream reservoir systems and other water management responses. It is the regulated response to climate change that is of much higher importance in evaluating future climate change impacts to future hydropower production. As presented in the April 8, 2021, IRPAC meeting,[160] regulated Brownlee inflow results from the RMJOC Part II study (which simulates regulated flow results for the Columbia and Snake River Basins based on climate change inputs from the RMJOC Part I study) did generally exhibit higher variability.[161] However, in the key months of July through December, the median historical values are very close to the median produced from Representative Concentration Pathways ("RCP") 4.5 and RCP 8.5 model runs.[162] Also, low flow conditions in the 90 percent exceedance and median model results are very similar to historical low flows.[163]

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[159] 2021 Northwest Power Plan at 52.
[160] Idaho Power, 2021 Integrated Resource Plan – Hydro Resources (Apr. 8, 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/2021_IRP_OperationsHydrology.pdf.
[161] Idaho Power, 2021 Integrated Resource Plan – Hydro Resources at Slide 28 of 83.
[162] Idaho Power, 2021 Integrated Resource Plan – Hydro Resources at Slide 30 of 83.
[163] Idaho Power, 2021 Integrated Resource Plan – Hydro Resources at Slide 32 of 83.

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Another element that is important based on the position of Idaho Power's hydropower system and management of the Snake River Basin is the influence that water management activities could have on future water supplies and hydropower generation. To Idaho Power's knowledge, the climate change and hydropower studies conducted by the NWPCC and the RMJOC do not consider key elements in the Snake River Basin such as weather modification, managed aquifer recharge, and administration of state agreements and water rights. As mentioned in the 2021 IRP, Idaho Power works closely with collaborators and Idaho state entities to implement a collaborative weather modification in several basins.[164] Idaho Power also engages with the Idaho state on water rights for hydropower projects and on administration of the Swan Falls Agreement, which secures a minimum flow at Swan Falls of 3,900 cubic feet per second ("cfs") during the irrigation season and 5,600 cfs during the non-irrigation season.[165] Finally, Idaho Power works closely with the Idaho Water Resources Board to track managed aquifer recharge efforts, which changes the timing and magnitude of flows to the Snake River from the Eastern Snake Plain Aquifer, as well as impacting surface water flow timing and magnitude.[166] These water management practices are vital to understanding the future of Idaho Power's hydropower potential and the modeling conducted for the IRP includes changes in streamflow and hydropower in response to these activities.

VIII. SUPPLY-SIDE RESOURCES

1. Solar/Storage Resources

Renewable Northwest recommends modeling multiple configurations of solar plus storage in the 2023 IRP and including longer-duration battery storage, which will provide firm capacity and support resource adequacy in the post-2030 timeframe.[167] The Company agrees with Renewable Northwest's recommendations and will continue to analyze hybrid resource configurations to best

[164] 2021 IRP at 20.
[165] 2021 IRP at 19-20.
[166] 2021 IRP at 20-21.
[167] Renewable Northwest's Comments at 4.

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meet system needs. The Company will also continue to solicit feedback from the IRPAC on potential supply-side resource options during the 2023 planning cycle. The Company would like to point out that both four- and eight-hour storage options were included in the 2021 IRP analysis and that the Preferred Portfolio includes a mix of both options. As the storage market evolves, the Company will continue to monitor developments and incorporate them into future IRPs.

2. <u>Coal-to-Natural Gas Conversion</u>

Renewable Northwest believes Idaho Power should reconsider investing in natural gas conversions in favor of cost-effective and reliable hybrid and standalone storage resources.[168] Renewable Northwest discusses the pitfalls in the ELCC determination of natural gas power plants and recommends Idaho Power model capacity values of thermal resources using an ELCC methodology that accounts for thermal derates due to weather-related conditions instead of using fixed Equivalent Forced Outage Rates ("EFOR") assumptions.[169] Idaho Power recognizes Renewable Northwest's concerns and would like to clarify that the 2021 IRP included thermal derates due to weather-related conditions *on top of* fixed EFOR assumptions in the AURORA modeling. The Company will continue to evaluate the most appropriate way to model capacity values for thermal resources in the 2023 IRP.

Renewable Northwest also recommends that Idaho Power clearly state its plans to model gas price uncertainty and update price curves to ensure that any coal-to-gas conversions for Bridger Units 1 and 2 are techno-economically feasible.[170] The Company continues to evaluate the conversion of Bridger Units 1 and 2 to natural gas to ensure that the conversion remains a least-cost, least-risk option. After testing the conversion's feasibility in the 2021 IRP, the Company has monitored the rapid developments in gas markets since February 2022 and the impact to forecast prices. Based on analysis with updated gas forecasts as of June 2022, the LTCE model

[168] Renewable Northwest's Comments at 4-5.
[169] Renewable Northwest's Comments at 7.
[170] Renewable Northwest's Comments at 7.

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continued to select both of these units for conversion to natural gas operation. The model has continued to identify the conversion as more cost effective than other available alternatives.

The recent natural gas price volatility will be discussed in the 2023 IRP process and the Company will adjust stochastic shocks based on these events and feedback from the IRPAC. The Company will also select an updated natural gas price forecast for the upcoming analysis.

3. Competitive Solicitation for Resource Procurement

Although Renewable Northwest states they take no position on the Company's recent RFP for battery storage and the build-own-transfer arrangement versus a Power Purchase Agreement ("PPA"), Renewable Northwest points out that Idaho Power, along with other utilities in the West, has yet to be fully equipped to operate and realize the entire value stream of battery storage technology, while storage developers have a significant level of expertise.[171] Renewable Northwest strongly recommends Idaho Power rethink its focus on owning resources and instead conduct a fair and transparent RFP process that is open to hybrid and standalone storage projects being offered as PPAs.[172] Idaho Power acknowledges Renewable Northwest's concerns and recommendations but would like to clarify that the Company does consider all ownership arrangements in the resource procurement process. As an example, Idaho Power in its most recent RFP solicited bids for both PPA and non-PPA ownership arrangements. Regardless, Idaho Power or other utilities' lack of previous battery storage experience/ownership should not preclude them acquiring battery storage resources under an ownership arrangement.

IX. STOP B2H'S COMMENTS

STOP B2H's Opening Comments focus on concerns related to the Company's 2021 IRPAC meetings, B2H cost estimates and transmission revenue used in the IRP analysis, and various transmission mapping issues.

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[171] Renewable Northwest's Comments at 6.
[172] Renewable Northwest's Comments at 7.

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A. Stakeholder Participation

STOP B2H believes the IRP process has become less transparent with the need for virtual meetings during the pandemic and believes the Company improperly restricted public participation to Question and Answer ("Q&A") format during those meetings.[173]

While virtual meetings have some drawbacks, they were a necessary safety precaution during the 2021 IRPAC process. During the 2021 planning process, the Company heard and sought feedback from IRPAC members and participants, all of whom noted that virtual meetings were preferred and allowed for greater and more consistent participation.

As a result of virtual access, the Company's IRPAC meetings often had upwards of 100 participants, resulting in the need to establish distinct participation options for formal IRPAC members versus interested members of the public. Attendees, whether IRPAC members or other individual participants, were encouraged to share thoughts and ask questions in all IRPAC meetings. The Q&A and chat features were available and open throughout each meeting. In addition, questions and comments were either addressed directly in real time during the meeting (through the chat feature in the meetings or verbally) or—where a question required more research or time did not allow a response during the meeting—answers were provided via email or posted to the IRP portion of Idaho Power's website after the meeting concluded. This format allowed for a more robust exchange of ideas and feedback than could be achieved through in-person meetings as there were multiple channels of communication available. Due to the availability of the chat function, attendees did not have to wait for a chance to be called on as they did in the past, with no other way to participate. And participants who may not have felt comfortable speaking aloud in the meeting were afforded an opportunity to participate in the chat.

During and after the 2021 IRP process, the Company reached out to IRPAC members to solicit feedback on the process. Even the few that missed in-person meetings appreciated the

[173] STOP B2H Coalition Opening Comments at 4 (July 7, 2022) [hereinafter, "STOP B2H Comments"].

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meeting layouts, facilitation, and the ease of participation. IRPAC members did not note any concerns about lack of transparency; in fact, several council members expressed that the 2021 process was more inclusive, more transparent, and less confrontational than in-person meetings in the past. This is also the feedback that Renewable Northwest provided in their Opening Comments. As in previous IRP cycles, meeting materials were posted on Idaho Power's website. Accordingly, as noted by other stakeholders in this process, Idaho Power made significant strides in providing greater transparency and opportunity for open participation in the 2021 IRP process.

B. B2H

1. <u>B2H Estimated Costs: Stale Forecast</u>

STOP B2H claims that the October 2016 budget continues to be "the budget of record."[174] While not altogether clear, Idaho Power assumes that STOP B2H is contending that the October 2016 cost estimate included in the 2017 IRP is the most recent estimate available. This claim is incorrect. On the contrary, as provided in Idaho Power's response to STOP B2H's Data Request No. 4, the Company developed in coordination with its contractor, HDR, Inc. ("HDR") an updated B2H estimate throughout 2021 as the Term Sheet was negotiated. The increased project cost associated with moving from 21 percent to 45 percent ownership are included in the estimate. Also as noted in that response, the 2021 IRP was developed throughout 2021 prior to major inflation, labor, and supply chain issues experienced over more recent months. The impact of these potential increases in costs are not isolated to the B2H project. Alternative non-B2H portfolios required a Gateway West segment for the increased resource build and would experience similar increased costs due to current economic conditions.

2. <u>B2H Estimated Costs: Budget Inconsistencies</u>

STOP B2H believes there are cost inconsistencies throughout the 2021 IRP and Appendix D, citing B2H cost values throughout the documents.[175] STOP B2H is mistaken. There are no

[174] STOP B2H Comments at 4-5, 7.
[175] STOP B2H Comments at 5.

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cost inconsistencies between the 2021 IRP report and Appendix D. The paragraph referenced by STOP B2H from the Executive Summary of Appendix D describes approximated costs of the B2H projects with no contingency and with a 30 percent contingency. The $485 million cost for B2H with 0 percent contingency is rounded up to $500 million and the $607 million cost for the B2H 30 percent contingency is rounded down to $600 million for the executive summary narrative. The various B2H costs presented throughout the 2021 IRP represent the robust risk analysis to validate B2H under various scenarios and there are no inconsistencies across the IRP and its appendices.

3. <u>Transmission Revenues</u>

STOP B2H details concerns that the wheeling charges necessary to transmit generated energy to Idaho Power's border are missing. As a result, STOP B2H says it is unable to see where or how the incremental transmission wheeling revenues are being credited to Idaho Power customers and would appreciate an explanation.[176] When analyzing B2H as a resource, the cost to install the project, along with the cost to purchase energy and wheeling charges to get energy to the Idaho Power border, are all considered. In AURORA, the cost of purchasing third-party transmission from Mid-C to the Longhorn terminus are included in the cost of energy. Therefore, the full cost of delivering power to the Idaho Power network and customers was modeled in the IRP analysis.

Regarding wheeling revenues, Idaho Power will not receive wheeling revenues for delivering purchased power across B2H to Idaho Power customers. Wheeling revenues are received by the Company for delivering power across the system for third parties. Transmission wheeling revenues are ultimately applied as a revenue credit in Idaho Power's retail base rate calculations. Increased transmission wheeling revenues reduce the transmission costs allocated to Idaho Power customers.

[176] STOP B2H Comments at 8.

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C. Transmission Mapping

STOP B2H notes that the transmission scenarios and modeling have become more complex in this IRP, making it difficult to follow. Citing the 2020 energy emergency event in California resulting in a rush by third parties to purchase additional transmission capacity, thereby reducing Idaho Power's access to Mid-C and other markets, STOP B2H lists actions by the Company to resolve this situation and comments on various transmission projects that would increase transmission capacity.[177] Below, the Company offers reply where necessary.

1. Alternate Markets

In 2021, Idaho Power issued an RFP for transmission and received no bids; therefore, the Company had to search out a complex sequence of transmission rights to meet capacity needs from other markets. STOP B2H asserts it has asked in past IRPs that the Company look to all available markets, not just the Mid-C, for energy and capacity.[178] The Company agrees and will continue to study all available energy market opportunities.

2. New Import Capacity in the Term Sheet

STOP B2H notes that while the B2H Term Sheet includes an added 200 MW of transmission import capacity acquired from PacifiCorp, it will not be used in planning margin calculations for the summer peaking months.[179] STOP B2H questions why this is the case when summer peak is so critical.[180] The Company believes this capacity provides long-term strategic value by providing access to a different market hub (i.e., Four Corners). The gained capacity that results from the 2022 B2H Term sheet will provide two diverse connections to two major western market hubs. As a conservative planning approach, the Company set the additional import capacity to 0 MW in the summer peaking months. But rather than consider Four Corners as providing no benefit in the summer, the Company looks at Four Corners as providing a summer

[177] STOP B2H Comments at 9-10.
[178] STOP B2H Comments at 9.
[179] STOP B2H Comments at 9.
[180] STOP B2H Comments at 9.

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capacity market hedge. Said another way, B2H provides 500 MW of capacity, Four Corners provides 200 MW of capacity, and the Company has conservatively elected to give the combined B2H and Four Corners capacities (the total B2H Term Sheet) 500 MW of summer peak load service capability. This further solidifies the 500 MW of capacity associated with the B2H Term Sheet, and the B2H project. Therefore, the 200 MW connection to Four Corners further solidifies and supports that the overall B2H project capacity will achieve at least 500 MW of peak import capacity from markets into Idaho Power during critical summer peaking months. The Company believes the access to this desert southwest hub will also prove extremely valuable during winter months in a low-carbon future.

3. Borah West and Midpoint

STOP B2H reinforces that Borah West and Midpoint West would afford Idaho Power an additional 510 MW of capacity.[181] Idaho Power agrees with the need for increased Borah West and Midpoint West capacity and has included Borah West and Midpoint West upgrades as part of the 2022 B2H Term Sheet.

4. Gateway West

STOP B2H recommends the Company utilize its Gateway West transmission rights that will give Idaho Power one-third of the 3,000 MW capacity (or 1,000 MW) and build Idaho Power Segments Phase 1 (Partial Segment 8 = 700 MW) and Phase 2 (Complete Segment 8 = 800 MW) to pick up 1,500 MW.[182] The Company will continue to evaluate Gateway West transmission projects in future IRPs. Gateway West was not selected in the Preferred Portfolio (but only narrowly not selected) in this IRP cycle. Increased resource builds across the Idaho Power system could trigger Gateway West builds in future Preferred Portfolios.

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[181] STOP B2H Comments at 9.
[182] STOP B2H Comments at 9.

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5. SWIP North

STOP B2H recommends examining SWIP-North to add 100 MW of summer capacity and 200 MW of winter capacity that would count toward meeting the Company's PRM.[183] The SWIP-North project was evaluated in the sensitivity case to determine whether further exploration was warranted. Idaho Power plans to perform a more detailed evaluation in future IRPs.

6. CBM and Transmission Reliability Margin ("TRM")

STOP B2H references the Company utilizing CBM and TRM for the first time to serve load and states "STOP has asked for this analysis in the past but the Company has not been willing to do it. Now they are using it as a resource we would like to see how it is being done."[184] STOP B2H's statements are incorrect. The Company's treatment of CBM and TRM in the 2021 IRP is identical to the Company's treatment of CBM and TRM in the 2019 IRP. The Company includes information about the consideration of CBM and TRM starting on Page 14 of Appendix D.[185]

STOP B2H claims the Company increased the PRM immediately, from 0.1 days per year (2019) to .05 days per year (2021), due to the NWPCC suggestion to do so.[186] STOP B2H states it is unfortunate that the difference in megawatt-hours and costs related to this change are unknown.[187] STOP B2H find this to be another example of Idaho Power obscuring the fiscal implications and budgetary forecasts.[188]

While the portfolio resource selection data for every portfolio is not available in the detail STOP B2H requested in its Data Request No. 14, the general impact of adjusting the PRM based on a 1 in 10 reliability metric to a 1 in 20 reliability metric are known. Idaho Power calculated the capacity needed for both 1 in 10 and 1 in 20 reliability levels using a benchmark year (in this case, 2023). The peak hour capabilities of solar, wind, battery, and DR were adjusted based on the

183 STOP B2H Comments at 10.
184 STOP B2H Comments at 10.
185 2021 IRP, App. D at 14-15.
186 STOP B2H Comments at 10.
187 STOP B2H Comments at 10.
188 STOP B2H Comments at 10.

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calculated ELCC determined from the LOLE analysis. Resource capacities were also adjusted to account for EFORs. For hydroelectric generation, expected case (50th percentile) water conditions were used.

The LOLE tool identifies the resources (in MWs) required by a perfect generation unit, with all transmission imports set to zero, to achieve the required reliability level. The difference between the reliability levels was approximately 73.5 MW of "perfect" generation. Using an SCCT with a 5 percent EFOR as the proxy resource, the difference in generation was about 77.4 MW. The 2022 levelized cost of an SCCT was $131.60 per kW. The resulting difference in annual revenue requirement can be calculated by multiplying the 77.4 MW by the levelized cost of the SCCT for a total of $10,185,840.

D. Idaho IRP Comments

STOP B2H also includes various portions of comments the Company received from parties in its Idaho 2021 IRP case. The Company responded to each of the issues raised in its reply comments, which can be found in Idaho Public Utilities Commission Docket No. IPC-E-21-43.[189] The table below provides a summary of the Idaho 2021 IRP comments introduced by STOP B2H and page references to the Company's Reply Comments on those topics.

Table 8 Reply Comment Reference in Docket IPC-E-21-43

Idaho IRP Comments	Idaho Power Reply Comments
Staff believes the Company should incorporate extreme weather evens and variability of water through load forecast instead of LOLE reliability target	Pages 5-6
Staff recommends only including market access backed by firm transmission in Load and Resource Balance	Pages 8-9
Staff is concerned with the use of a single benchmark year (2023) to determine the LOLE-based PRM	Pages 7-8

[189] *In re Idaho Power Company's 2021 Integrated Resource Plan*, Idaho Public Utilities Commission, Docket No. IPC-E-21-43, Idaho Power Company's Reply Comments (June 30, 2022), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2143/Company/20220630Reply%20Comments.pdf.

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Staff recommends the Company provide a comprehensive Quality Assurance plan to verify and validate its models, describing the purpose of each test, how the test was conducted and the result.	Pages 9-10
Staff requests the Company Include a study of the costs and benefits of implementing a flexible resource strategy.	Pages 16-17
Staff requests the Company develop a Bridger exit agreement with PacifiCorp that determines potential costs of extending or exiting operations early - like the exit agreement developed for Valmy.	Pages 17-18
Staff recommends the Company not including acquisition of specific types of resources in its action plan where a broadly scoped RFP is appropriate.	Page 21
Staff did not agree with the Company's conclusions regarding an additional portfolio modeled to test B2H as an independent variable.	Pages 10-13
Staff has two concerns related to risk: How much the Company is relying on B2H to meet future needs and lack of risk mitigation and flexibility strategies included in the Company's IRP.	Pages 13-17
Clean Energy Opportunities shared concerns around AURORA developed market prices and discount rates.	Pages 22-25
Idaho Conservation League ("ICL") shared concerns around Bridger conversion to natural gas being late in the process and it is speculative.	Page 26

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 4th day of August 2022.

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ATTACHMENT 1

to

Idaho Power’s Reply Comments

THIS ATTACHMENT IS HIGHLY CONFIDENTIAL

AND WILL BE PROVIDED SEPARATELY ONCE A MODIFIED PROTECTIVE ORDER IS IN PLACE

DOCKET LC 78 - CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the confidential pages of Idaho Power Company's Errata to Reply Comments, on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: August 16, 2022

/s/ Alisha Till
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