BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 78

In the Matter of IDAHO POWER COMPANY, 2021 Integrated Resource Plan	FINAL COMMENTS

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Introduction

Idaho Power Company's (Idaho Power, IPC, or the Company) 2021 IRP has provided a framework for understanding the Company's 20-year plan to acquire resources to serve customers. Staff has appreciated a productive conversation with Idaho Power and stakeholders during this proceeding.

In addition to Staff, four intervening parties provided Opening Comments (Comments) in response to the 2021 IRP: the Oregon Citizens' Utility Board (CUB), the Renewable Energy Coalition (REC), Renewable Northwest, and the StopB2H Coalition (STOP):

- CUB's Comments are mainly concerned with the "major and rapid shift in the Company's load and resource balance from a resource sufficient to a significantly resource deficient status."[1] CUB discusses the factors that have contributed to this shift, the additional scrutiny required due to this change, and the Company's readiness to meet the additional needs and procure necessary resources.
- REC's Comments focus on the Company's planning assumptions regarding the renewal of qualifying facilities (QF).[2] REC is supportive of the renewal assumption in the 2021 IRP provided Idaho Power provides a more empirical basis for the assumed renewal rate in the next IRP.
- Renewable Northwest provides general support for the Company's IRP stakeholder process and portfolio modeling framework, while also making specific recommendations to enhance the analysis and ensure the selection of the least cost, least risk portfolio. Renewable Northwest encourages IPC to re-consider company ownership of storage resources and instead open resource procurement to third-party power purchase agreements (PPA).[3]
- STOP expresses their concerns about the significant changes in data and methods used in this IRP compared to the 2019 IRP and the limited time and access that stakeholders had to assess those changes. STOP further comments on issues around transmission mapping, the projected Boardman to Hemingway (B2H) transmission project costs, and wheeling revenue.[4] Finally, STOP summarizes comments from the Idaho Public Utilities Commission (IPUC) docket, IPC-E-21-43, which reviewed the Company's 2021 IRP.

The stakeholders' diverse views are described in more detail throughout these Final Comments. In these Final Comments, Staff describes the status of our review of the Company's load forecast, makes recommendations for the 2021 IRP, makes recommendations for the 2023 IRP, describes other stakeholder topics that were outside the scope of Staff's recommendations, and finally Staff discusses Idaho Power's emissions.

[1] See Docket No. LC 78, CUB, Opening Comments, July 7, 2022, p 1.
[2] See Docket No. LC 78, REC, Opening Comments, July 7, 2022, p 1.
[3] See Docket No. LC 78, Renewable Northwest, July 7, 2022, p 1.
[4] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 4.

Load Forecast

As noted in Comments, there has been a significant shift Idaho Power's resource position. In its 2021 IRP, Idaho Power identifies a capacity deficit of 101 MW in 2023 that keeps growing in the next few years. This is a major departure from the 2019 IRP, in which the first capacity deficit of only 42 MW was detected in July 2029.[5] According to Idaho Power, the shift from sufficiency to deficiency is based on a combination of factors including transmission constraints, reduced ability of existing demand response (DR) programs to serve peak load hours, planning margins and methodology modernization, and higher than expected load forecast.[6]

Idaho Power's load forecast comes in two forms: hourly and monthly. In Comments, Staff had received too little supporting material for the Company's load forecast to make a conclusion about the reasonableness of either. Since then, Staff has met with Idaho Power on this topic twice, sent several requests for more information, and can draw a conclusion on the hourly load forecast. Staff requires more information before reaching a conclusion the reasonableness of the monthly load forecast.

Hourly Load Forecast

Staff's initial reading of the 2021 IRP Appendix A's description of the hourly load forecast's use of a neural network was like CUB's reading. CUB identifies several concerns with the 2021 IRP load forecast. First, CUB notes that it is currently unclear what improvements were made by the Idaho Power's change from a linear regression model to a neural network.[7] The Company used a neural network to forecast hourly system load in this IRP. CUB states that this approach is essentially a black box modeling technique and lacks the clarity offered by regression models. Second, the neural network model uses historical weather data, which do not necessarily account for the in-migration of load that drives growth and capacity needs.[8]

Regarding the neural network, CUB makes two requests of Idaho Power.[9] First CUB requests the Company provide more information on how the neural network model is an improvement over the linear regression model. Second, 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.

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[5] See Docket No. LC 78, CUB Opening Comments July 7, 2021, p. 1.
[6] See Docket No. LC 78, CUB Opening Comments July 7, 2021, pp. 1-2.
[7] See Docket No. LC 78, CUB Opening Comments, July 7, 2021, p7.
[8] See Docket No. LC 78, CUB Opening Comments, July 7, 2021, p7.
[9] See Docket No. LC 78, CUB, Opening Comments, July 7, 2021, pp 6-7.

Idaho Power acknowledges that the introduction of the neural network model adds complexity. Responding to the two questions posed by CUB, the Company explains that the neural network is only used to develop the hourly profile and that the monthly energy and demand are determined based on the Company's established peak and load framework (using an Ordinary Least Squares methodology).[10] The output of a neural network is used to shape the hourly profile of load but does not inform system load and peak and as such does not account for unusual load conditions.

Staff met with Idaho Power to discuss the neural network method used in the hourly load forecast. Staff finds this to be a reasonable technique of distributing the system load estimated in the monthly load forecast into hourly intervals. Idaho power does not use the neural network to estimate the overall size of system load. Instead, the scope of the hourly forecast is limited to identifying the hours in which the monthly load forecast are entered into Aurora.

Monthly Load Forecast

The monthly load forecast uses nineteen separate regression models. A different monthly peak demand for the Company's system is estimated for the twelve months of the year. Monthly energy demand is estimated separately for each customer class. One regression model is used to estimate residential energy load. One regression model is used to estimate the energy load of commercial customers with less than one MW of demand capacity. One regression model is used to estimate irrigation. Both the commercial load greater than 1 MW and industrial load have separate regression models for manufacturing and service.

Customers with more than 20 MW of demand capacity are a separate class from industrial load, called Additional Firm Load. These customers are required to have special contract. Idaho Power estimates the future load of these special contract customers using information provided by the customer.

CUB notes that the forecasted load growth is in part driven by high-density customers in Idaho Power's service territory - specifically large-scale cryptocurrency mining operators. Such customers can now be served by an interruptible service, which impacts the forecasted capacity shortfall. CUB requests the Company explain the impact of having cryptocurrency mining operations under an interruptible service. Responding to CUB, the Company states that speculative load (including cryptocurrency mining operations at this time) is not included in the load forecast.[11]

Staff thanks the Company for clarifying for CUB that large cryptocurrency mining is not included in the load forecast at this time, but the Company's method of forecasting Additional Firm Load appears to Staff to contain speculative load. Staff does not see that as inherently a problem. Forecasting is by nature speculation about the future, but Staff is not sure how Idaho Power

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[10] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, pp 53-54.
[11] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p55.

processes special contract customers' speculation of their future load. In OPUC IR 132, Staff sought the source material for these estimates. Because Staff used the word "extrapolation" in the request, the Company narrowly interpreted that word to only mean a specific technique of extrapolation, linear extrapolation. Idaho Power's response stated "[t]he Company does not implement a linear extrapolation of a variables as may be implied for Additional Firm Sales to customers" and did not provide the supporting material.[12] Staff will work with Idaho Power to get the documentation necessary to review this portion of the Company's load forecast.

Staff has received incomplete responses in other ways. For Idaho Power's nineteen regression models, Staff sought data from "the most recent period that data is available for all variables for all regression models."[13] The latest period the Company provided data for was June 2021. In OPUC IR 135, Staff requested the current future values from third-party data sources that are used to plug into the independent variables. The Company replied these were already provided in response to OPUC IR 128. Yet the future values in OPUC IR 128 are of 2021 vintage or older and not the current values. Perhaps these omissions were all inadvertent. Staff will work with the Company to get this data.

To follow up on Idaho Power's references to statistical techniques of sample testing and probability estimation, Staff requested the workpapers behind these analyses. The Company did not share this information, citing a reason that IPC has used several times:

> As mentioned in the Company's responses to OPUC Staff's DRs 16, 128, 129, 140, 141, and 142 in LC 78, there are no Excel-based workpapers, as analysis is performed within proprietary databases used by the Company. In this case, the analysis is maintained in an Oracle OLAP database. The source code for data derivation and extraction is proprietary Oracle language (DML).[14]

Staff will work with Idaho Power to overcome this barrier. Public review of Idaho Power's load forecast requires transparency of the methods and data used, which should not be hidden in the black box of an electric company's data base.

Recommendations for the 2021 IRP

Staff's recommendations for the 2021 IRP are limited to recommendations for additional analysis to establish the reasonableness of some of the assumptions that underlie Idaho Power's 2021 Action Plan. Staff recommends the Company perform additional modeling in this IRP with modified assumptions regarding the nameplate capacity of existing DR, forecasted wholesale sales prices, capital costs of a combined cycle combustion turbine, Investment Tax Credits, and Production Tax Credits.

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[12] See Docket No. LC 78, Idaho Power, Response to OPUC IR 132, September 1, 2022, p 1.
[13] See Docket No. LC 78, OPUC Staff, OPUC IR 128 and 129, August 16, 2022, pp 1-2.
[14] See Docket No. LC 78, Idaho Power, Response to OPUC IR 143, September 2, 2022, p 1.

Nameplate Capacity of Existing Demand Response (DR)

Staff recommends that the Company use observed data from 2022 to update the assumed nameplate capacity of existing DR to avoid overestimation of the number of resources to procure in its requests for proposal (RFP). Additional analysis based on data from the 2022 DR Season will show whether the 2021 IRP's assumptions about the decline in nameplate capacity of its DR programs are born out.

In its 2021 IRP, Idaho Power reduced the nameplate capacity of existing DR from the 380 MW used in the 2019 IRP to 300 MW to account for expected changes in subscription and realization rates due to program changes made last year. In response to OPUC IR 94, the Company provided an update to that estimate as of June 3, 2022, revealing the nameplate capacity of existing DR to be 22.9 MW higher than was previously estimated.

That was at the beginning of the peak season. Idaho Power's 2022 peak season is now ending, and observed realization rates, the rate at which program participants do not opt out of events, will have become available when the Company's Final Reply Comments are due on September 23, 2022, offering a more reliable basis for planning assumptions than survey research.

In response to both Staff and CUB Comments requesting a further update on the observed nameplate capacity of Idaho Power's DR in 2022, the Company states in Reply Comments that it will evaluate its DR program after the 2022 season and update assumptions, as necessary, in the 2023 IRP.[15] A further update of the nameplate capacity of existing DR should not wait until the 2023 IRP. The DR program windows for the 2022 peak season will close next week while subscription and realization rates are relatively simple data sets to infer a nameplate capacity from. **The 2021 IRP should replace the 2021 assumptions of the nameplate capacity of existing DR with real-world observations from 2022.**

Wholesale Energy Prices

Staff believes Idaho Power's 2021 IRP significantly underestimates wholesale energy prices during the years of the Action Plan and beyond. This underestimation biases portfolio modeling in favor of energy storage, market purchases, and by extension, the construction of transmission resources for expanding capacity for market purchases. Staff observed a wide disparity between forecasted prices for Mid-Columbia (Mid-C) and actual 2021 prices. The Company pointed to the low hydro conditions last year, offering a plausible explanation for a one-off event. However, a comparison of the forward trading curve for two wholesale markets

[15] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 56.

Idaho Power plans to import from (Mid-C and Palo Verde) with the Company's forecast of these prices in the 2021 IRP, that Idaho Power presents in Reply Comments, shows a persistent underestimation of wholesale prices in both these markets for nine years.

Figure 1

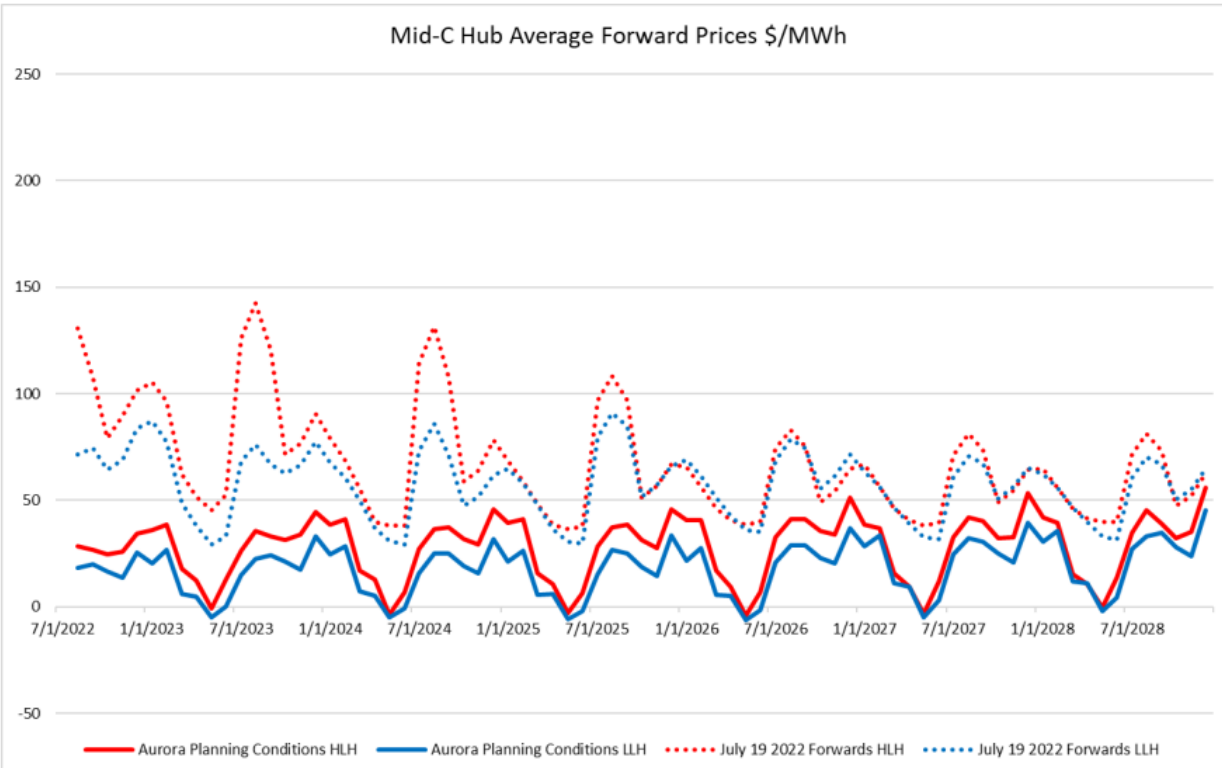
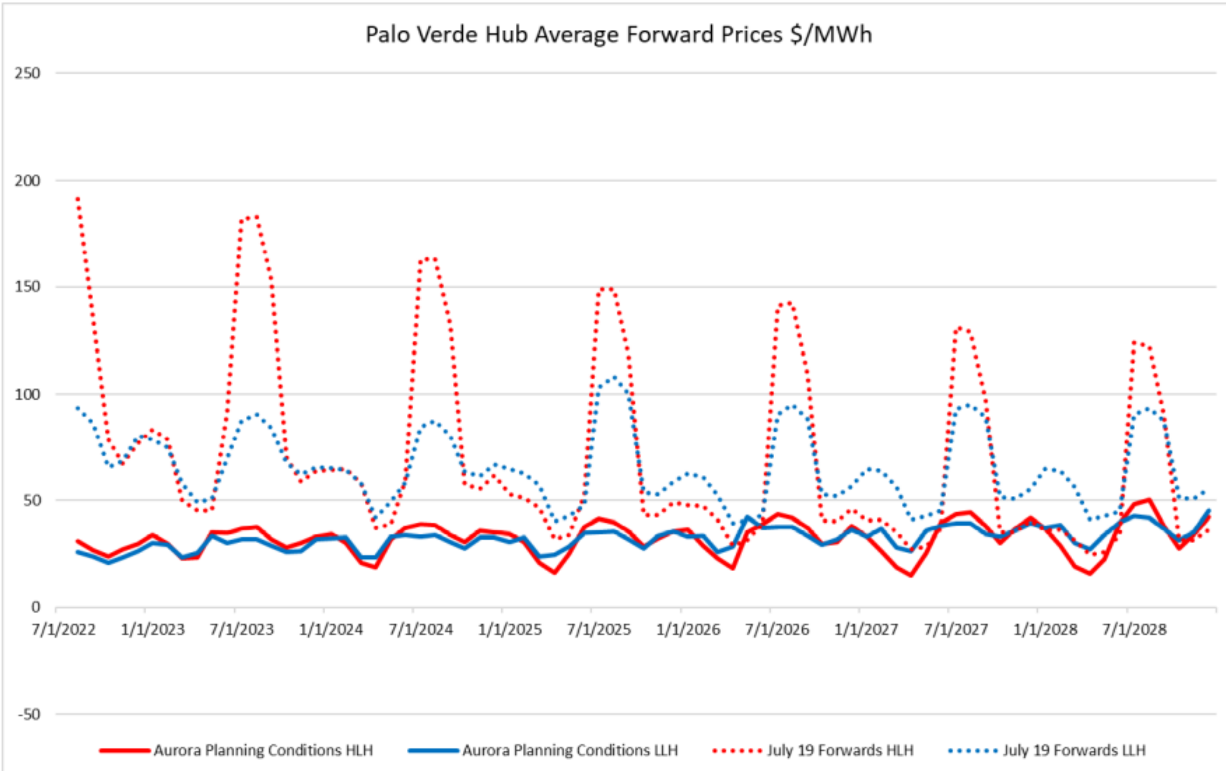


Figure 2



Staff does not find Idaho Power's arguments in defense of the 2021 IRP's wholesale price forecasts persuasive. In Reply Comments, Idaho Power makes three points. First, the Company states that "the ex-ante wholesale prices generated by AURORA are based on typical or planning conditions generated before actual conditions occur."[16] IPC goes on to say: "It should not be a surprise, then, that actual wholesale prices differ from AURORA's ex-ante modeled prices." Staff agrees that it would be unreasonable to expect a model to forecast the exact prices that eventually occur, but the difference between a good model of prices and actual prices is the jagged spikes of day-to-day trades in a real market in contrast to the relatively smooth estimate a model generates. However, a good model would deviate from reality without bias, with real prices falling both higher and lower than the model predicts, producing equal error in both directions. Instead, Idaho Power's modeling of wholesale prices shows a clear downward bias. Real prices are consistently and significantly higher.

Even Idaho Power's stochastic risk analysis has a downward bias. In Comments, Staff requested the Company: "Compare the 2021 IRP's Mid-C forecast under low hydro conditions in 2021 with observed 2021 prices."[17] Staff is surprised that in Reply Comments, the Company states it cannot meet that request. Given that Idaho Power included hydro conditions in the Company's

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[16] Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 20.
[17] Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 19.

stochastic risk analysis, we believe they already performed the analysis. In the range of forecast Mid-C prices in 2021 from Idaho Power's stochastic risk analysis, the highest forecasted average price for the entire year is $37 per MWh in December which undershot the average historical price of that month by 29 percent.[18] The highest forecasted prices for the 2021 peak season undershot actual prices by an even higher margin. The highest forecasted average price for MWhs in June, July, and August of last year was $15, $11, and $26, respectively. Actual average market prices were $59, $98, and $63, an average underestimation of 74 percent.[19] So, not only does Idaho Power's planning case forecast underestimate Mid-C prices over the course of this decade, the Company's stochastic risk analysis also significantly underestimates Mid-C prices in the first observed low hydro year of this decade.

Second, the Company states that the 2021 IRP used a forecast of the Western Electric Coordinating Council (WECC) resource buildout that is generally similar to the Northwest Power and Conservation Council (NWPCC)'s forecast.[20] This is a helpful clarification, suggesting that the source of Idaho Power's underestimation of wholesale prices might not come from the assumed regional resource buildout. However, this explanation does not offer a premise on which to expect peak Mid-C prices to generally be less than $15 per MWh next July when market participants risking their own capital are purchasing futures contracts for far above that.

Third, the Company states: "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."[21] On the contrary, it seems unlikely that wholesale market traders have missed the major shift to renewable resources. The transition to clean energy may one day lead to lower average wholesale prices, but that does not necessarily mean that such saving will be realized in the next decade. Another conjecture is that wholesale markets are pricing in the scarcity risk that comes with the retirement of dispatchable resources followed by an expected greater penetration of variable energy resources (VER). In Reply Comments, the Company states "AURORA is not designed to capture price spikes as it does not have a scarcity pricing mechanism."[22] That might mean Aurora is not designed to forecast wholesale prices in the 2020s. Market participants may also be pricing in a higher frequency of low hydro conditions and a higher political risk for dam removal.

[18] Docket No. LC 78, Idaho Power, Response to OPUC IR 144. September 2, 2022, Column E.
[19] LC-78 IPC Response to Staff-s IR No 26_Attach 1_MidC – 17 -22 Averaged ES.xlsx.
[20] Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, pp 21, 22.
[21] Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 24.
[22] Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 24.

Reasonable alternatives to Idaho Power's wholesale price forecast exist: historical prices in 2021 and 2022 and the latest forward price curve through most of this present decade. **The assumed wholesale prices for the period 2022-2029 for the 2021 IRP should be updated with observed historical prices and observed futures prices.**[23]

Combined Cycle Combustion Turbine (CCCT) Capital Cost

At $1,656 per kW, Idaho Power's 2021 IRP assumes an unreasonably high capital cost for a CCCT plant. Though Staff believes that compounding the 2012 capital cost of Langley Gulch at the rate of the observed price escalation of spare parts is a questionable method, this approach did put the Company's modeling near the range of published research, albeit at 6 percent of Lazard's upper range value of $1,300 per kW.[24] The Company then marked that capital cost up another 20 percent to include alternative fuel blending. Staff finds this unreasonable. Staff believes including an alternative fuel option can be appropriate, but that inclusion should not come at the exclusion of considering standard CCCT technology. **Idaho Power should either assume a capital cost of $1,300 per kW or use a capital cost from observed bids from a current all source RFP.**

Investment Tax Credit (ITC) and Production Tax Credit (PTC)

The 2021 IRP reasonably modeled the ITC and PTC as they existed just weeks ago, but the Inflation Reduction Act (IRA) made significant changes to these federal subsidies of energy projects. Though the ramifications of this new law may have a variety of impacts that are too complicated to understand at this time, a review of this law has identified three clear modeling inputs that should be changed. **1) Extend the ITC for solar and battery storage (including standalone storage) at the 30 percent level through 2032. 2) Extend the PTC for wind at the 1.5 cents/kWh level through 2032. 3) Allow new nuclear and green hydrogen plants to claim an ITC/PTC from 2025 through 2032.**

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[23] Staff has not attempted to determine the reasonableness of Idaho Power's wholesale price forecast for the 2030s and has no alternative price forecast to recommend in its place.

[24] Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 25.

Staff Recommendation 1: The Company rerun its Aurora modeling by updating:

- **The nameplate of existing DR to what was observed in 2022,**
- **The endogenous wholesale price forecast with an exogenous entry of historical prices and current futures prices,**
- **The capital cost of a CCCT plant with $1,300 per kW or an observed capital cost from an RFP bid,**
- **The ITC for solar and battery storage (including standalone storage) at the 30 percent level through 2032,**
- **The PTC for wind at the 1.5 cents/kWh level through 2032,**
- **And extend both the ITC and PTC for nuclear and green hydrogen from 2025 through 2032.**
- **After completing this modeling update, present the results in the Company's Reply Comments and detail how it impacts the 2021 Action Plan.**

Recommendations for the 2023 IRP

Modeling New Demand Response

Idaho Power estimates a potential of 284 MW of new DR capacity. The 2021 IRP Preferred Portfolio selected only 100 MW of this new DR over the planning horizon, leaving 184 MW undeveloped. Staff continues to seek to understand why the Preferred Portfolio fails to maximize all potential DR. Staff has sought to understand the factors impacting DR selection, whether the Company:

- Assumed new DR costs that are too high
- Assumed new DR ELCC that are too low
- Assumed declining capacity contribution for future DR that is inconsistent with the Company's modeling of other resources
- Modeled new DR in Aurora improperly.

While Staff has remaining questions about how new DR is modeled in the 2021 IRP, Staff does not recommend alternative modeling choices for any of these factors. Instead, Staff looks forward to working with Idaho Power and stakeholders as the Company transitions from NWPCC data to IPC-specific data on DR potential.

Assumed Cost of New DR

In Comments, Staff noted that the Company's cost assumptions for new DR appear reasonable and that the preferred portfolio's failure to maximize all potential DR is not likely due to unreasonably high DR cost assumptions. That is because, even if the cost assumptions are higher than the true cost of DR, the Company's assumed DR costs are significantly lower than other resources. However, Staff believes the cost assumptions of potential DR merit further discussion.

In Idaho Power's response to OPUC IR 105, the Company explains that the additional 284 MW of DR capacity was grouped into 20 MW bundles and further divided into two price buckets. The first 100 MW was evaluated using the first price bucket: $51.42/kilowatt year (kW-year). The remaining 180 MW was evaluated using the second price bucket: $81.99/kW-year.[25] The $51.42/kW-year was determined as part of Docket No. ADV 1355 and was considered the maximum cost the Company should pay for any DR expansion that had the characteristics of the existing modified programs.[26] The $81.99/kW was a weighted average price of the NWPCC assessment of DR programs (excluding programs similar to the Company's existing offerings, pricing programs, and the three highest cost programs).[27]

To better understand this approach, and the batching of DR into 100 MW and 180 MW allotments, Staff sought to reconcile the kinds of potential DR, and the estimated amount of capacity from the Company's response to OPUC IR 96, with the updated levelized costs for those kinds of DR from Idaho Power's response to OPUC IR 105. Table 1, provided by the Company, presents the kinds of potential DR and the estimated amount of capacity of each.[28]

[25] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 105, June 15, 2022.
[26] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 105, June 15, 2022.
[27] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 105, June 15, 2022.
[28] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 96, Attachment 1, tab labeled "IPC DR Potential Analysis."

Table 1: Adjusted IPC Potential Based on Program Type

Product	Idaho Power Allocation (MW)
ResCPP	29.9
ComCPP	15.9
IndCPP	12.9
IndRTP	2.9
ResERWHDLCGrd	103.1
ResERWHDLCSwch	9.1
ResBYOT	7.5
NRCoolSwchMed	5.7
NRTstatSm	2.7
NRCoolSwchSm	1.8
DVR	66.7
ResTOU	25.4
MW Total	**284**

Table 2 presents the same kinds of potential DR and estimated capacity as Table 1 but includes costs from Idaho Power's response to OPUC IR 105 and is presented from lowest to highest cost resource.[29] Staff notes that while the costs of the pricing programs are included here, those programs were excluded from the weighted average price analysis the Company described in IR 105.

[29] See Docket No. LC 78, Idaho Power, Response to OPUC IR 105, June 15, 2022, attached spreadsheet, tab labeled "DR2 Cost Calc."

Table 2: Adjusted IPC Potential Based on Program Type

Product	Idaho Power Allocation (MW)	Updated Levelized Cost - Utility costs $/KW/yr	Alternative Grouping
ComCPP	15.9	$3.65	167 MW of capacity from programs with cost less than $51/kW
ResCPP	29.9	$8.13	
IndCPP	12.9	$9.12	
IndRTP	2.9	$12.37	
ResTOU	25.4	$17.40	
DVR	66.7	$19.67	
NRCoolSwchMed	5.7	$29.41	
ResBYOT	7.5	$40.22	
NRTstatSm	2.7	$65.74	117 MW of capacity from programs with cost greater than $51/kW
NRCoolSwchSm	1.8	$115.42	
ResERWHDLCGrd	103.1	$118.54	
ResERWHDLCSwch	9.1	$190.34	
MW Total	**284**		

Table 2 suggests that more than 160 MW of potential DR is available at a cost of less than $51/kW-year. This is a greater amount than the 100 MW that was evaluated in the 2021 IRP modeling using the first price bucket of $51.42/kW-year. Table 3 below compares the amount of potential DR as modeled in the 2021 IRP to the apparent amount of potential DR based on Idaho Power's responses to OPUC IRs 96 and 105.

Table 3: Potential DR Amounts

	As modeled potential DR amount	Apparent potential DR amount, based on Information Requests 96 and 105
$51.42/kW	100 MW	167 MW
$81.99/kW	180 MW	117 MW

Staff welcomes correction if the preceding reconciliation of kinds of potential DR, estimated amount of potential DR, and estimated costs of potential DR contains errors. Staff also welcomes explanation or clarification about why 100 MW is a more appropriate allotment to evaluate using the first price bucket of $51.42/kW than smaller buckets with smaller costs.

Effective Load Carry Capability of New DR And Other Resources

CUB notes that the Company's introduction of ELCC has resulted in a significantly lower capacity contribution for DR programs compared to prior IRPs. Furthermore, CUB raised concerns with the Company's planning margin approach for evaluating system needs and determining generation resource contributions, specifically for DR. The Company used a Loss of Load Expectations (LOLE) method which assigned an ELCC percentage to DR.[30] However, the Western Resource Adequacy Program (WRAP), which the Company is a participating utility in, recommends using "operational testing and historical performance" for DR capacity determinations.[31] CUB requests the Company elaborate on whether Idaho Power's approach to DR evaluation can be reconciled with WRAP's methodology, as well as on whether the ELCC methodology results in a significantly diminished capacity contribution for DR resources compared to how they have historically performed.

Idaho Power replies that the Company will review the resource accreditation for energy resources and whether it makes sense to use them in future IRPs. Idaho Power points out that regional values are not always representative of local systems and commits to share details of WRAP standards with the IRP Advisory Committee as they become available.[32]

Regarding the comparison of the capacity contribution of DR in the 2021 IRP and how it has historically performed, the Company states that when the DR programs were designed, the hours of highest risk were aligned with the hours of highest load given the small penetration of VER at the time. However, with the recent increase of VER penetration, the hours of highest risk are no longer necessarily aligning with the hours of highest load. According to the Company, the use of the ELCC methodology quantifies the reduction of the DR programs' effectiveness as the system buildout changes.[33]

Staff finds no fault in Idaho Power's estimate of the ELCC of DR or any other resources. Staff reviewed but has not replicated or validated the Company's MATLAB scripts. In a meeting with IPC on August 22, 2022, Staff was able to confirm with more technical certainty what the Company states in its Reply Comments, that the diminishing marginal capacity contribution of DR is consistent with the same modeled trend of other resources.

[30] See LC 78, CUB, Opening Comments, July 7, 2022, p 5.
[31] See LC 78, CUB, Opening Comments, July 7, 2022, p 6.
[32] See, LC 78, Idaho Power, Reply Comments, August 4, 2022, p 52.
[33] See, LC 78, Idaho Power, Reply Comments, August 4, 2022, p 52.

New DR Inputs for Aurora

Staff has two remaining questions about how new DR is modeled in Aurora. First, was the 20 MW block size for new DR appropriate for optimal Aurora selection? Second, did the Company make new DR available for dispatch in hours that optimized DR's value?

In Comments, Staff requested the Company explain why the size of a new DR block for Aurora selection was increased 400 percent from 5 MW in the last IRP. The Company replies that it believes the use of 20 MW blocks more accurately reflects that a program could achieve up to 20 MW each year if the customer potential were accurately estimated. Furthermore, the use of 20 MW blocks gave Aurora more DR to fill a potential deficit if needed.[34]

Regarding the use of 20 MW blocks to give Aurora more DR to fill a potential deficit, Staff understands that the prior increment of 5 MW was not a cap on potential DR capacity, rather it was simply a smaller increment of capacity for the model to select. Had there been a 20 MW potential deficit the model could have selected 4 units of 5 MW. Staff welcomes correction if this understanding is incorrect. Absent correction, Staff is concerned that DR could have been optimal in annual increments smaller than 20 MW, but a minimum size 20 MW prevented this cumulative selection.

Regarding the use of 20 MW blocks to accurately reflect what the program could achieve each year, Staff reviewed Table 6.3 of the IRP and found that the existing programs delivered the following capacity amounts in 2020:

- A/C Cool Credit: 32 MW
- Flex Peak: 36 MW
- Irrigation Peak Rewards: 298 MW.[35]

Staff also examined the estimated capacity potential of additional DR programs presented in OPUC IR 96. For 10 of the 12 programs these amounts varied from 1.8 MW to just under 30 MW, with two exceptions of programs at 66 MW and 103 MW.[36]

An addition of 20 MW to either of the existing A/C Cool Credit or Flex Peak programs would represent large increases, over 62 percent and over 55 percent, respectively. An addition of 20 MW would also represent a large increase for 10 of the 12 programs considered for potential additional capacity. And while the percentage increase of 20 MW for Irrigation Peak Rewards is

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[34] See, LC 78, Idaho Power, Reply Comments, August 4, 2022, p 18.
[35] See Docket No. LC 78, Idaho Power, IRP, December 30, 2022, p 68.
[36] See Docket No. LC 78, Idaho Power, Response to OPUC IR 96, June 10, 2022, tab labeled "IPC DR Potential Analysis."

smaller (just over 6 percent), given the scale of the other two existing programs, and those presented as sources of potential additional capacity, Staff is uncompelled by the Company's argument and finds a more granular approach to modeling additional DR capacity to be more appropriate.

In Comments, Staff has requested the Company explain how the hours when DR was given a forced outage rate less than 100 percent were chosen.[37] The Company used Aurora's forced outage function to manually enter when DR can be dispatched. A forced outage rate of 100 percent prevents DR from being dispatched. The Company replied that the hours when DR was used, or given a forced outage rate less than 100 percent, were computed by Idaho Power's internally developed 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 the constraints associated with the different DR programs, the tool created an hourly dispatch shape for the DR portfolio. The load profile and resources each 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 Long-Term Capacity Expansion (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.

An analysis of the hourly forced outage rates in comparison to hourly loss of load probability (LOLP) estimates provided by Idaho Power may help assess whether the Company's DR shapes are effectively being applied to the hours of highest risk. This analysis found that for every year, there are multiple instances in which some of the highest risk hours within the DR program window are given a forced outrage rate of 100 percent, indicating that DR was not used for these hours. For example, on July 31, 2025, the hour ending 20 has a forced outage rate of 100, even though it has a higher LOLP, and therefore higher risk, than hour ending 21, which is given a forced outage rate of 83 percent and uses DR. For any given year, at least 40 percent of the top 50 hours with the highest LOLP values (during the program window), receive a forced outage rate of 100 percent, preventing DR selection. This might mean that for modeling purposes, DR is at least 40 percent less effective than it could be if fully dispatched during the highest risk hours.

[37] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 18.

Table 4: Distribution of DR Forced Outage Rates for the Top 50 Highest LOLP Hours in Each Year (that fall within DR program hours)

	33.3%	*50%*	*66.7%*	*83.3%*	*100%*	*Share at 100%*
2022	0	13	10	5	22	44%
2023	0	4	4	6	36	72%
2024	0	5	10	6	29	58%
2025	0	4	4	6	37	73%
2026	0	6	5	9	30	60%
2027	1	10	7	8	24	48%
2028	0	9	4	10	27	54%
2029	3	6	9	12	22	42%
2030	0	2	10	4	34	68%
2031	0	8	5	7	30	60%
2032	2	5	3	7	33	66%
2033	1	7	2	7	33	66%
2034	0	1	6	7	36	72%
2035	0	4	3	8	35	70%
2036	0	5	6	4	35	70%
2037	0	5	5	7	33	66%
2038	0	8	1	7	35	69%
2039	0	7	3	5	35	70%
2040	0	5	4	6	35	70%
Total	***7***	***114***	***101***	***131***	***601***	***63%***

The results of this analysis might contradict Idaho Power's stated methodology of allowing the dispatch of DR in hours of highest risk and suggest that the Company is not always applying DR when it would be most beneficial, which may ultimately overstate the need for additional resources.

At a meeting with the Company on August 23, 2022, Staff discussed how to interpret results like this. Idaho Power suggested that the hours with the highest LOLP change when DR is dispatched. Perhaps hours when DR was not available have a higher LOLP precisely because DR was not available, if there truly was a dynamic relationship between the LOLP hours the Company shared in response to OPUC IR 41 and the forced outage inputs IPC shared in response to OPUC IR 95. Another possible explanation is that the missed high LOLP hours occur on the other nights of the week that DR events were called, but DR program restraint limit how often events can be called per week.

While Staff has lingering questions about how new DR was modeled in the 2021 IRP, we recognize the data source for modeling new DR is about to change. Staff understands there is an IPC-specific DR potential study that is currently underway and expected to be complete by the fall of 2022.[38] While Staff appreciates the effort and analysis put into modeling future DR in the 2021 IRP, Staff is hopeful that the forthcoming DR potential study better informs the modeling of future DR for the 2023 IRP. Staff is interested in whether the DR potential study finds the Company's current DR programs have potential to expand. Staff is encouraged by the Company's statement, in Reply Comments, that Idaho Power believes it is appropriate that specific potential programs are informed by this potential study.[39] Staff is further encouraged by the Company's agreement with CUB, in the first round of comments, that a holistic approach should be taken in modeling both traditional DR programs as well as pricing programs and is including pricing programs as part of the DR potential study that will inform the 2023 IRP.[40]

Staff Recommendation 2: The Company model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.

Transmission

Staff's final comments on transmission planning will mainly focus on the key issues raised by both Staff and stakeholders in their respective opening comments or information requests, as well as the response provided by Idaho Power in its Reply Comments or information request responses. The two main areas of interest are the transmission availability to access wholesale power markets and several aspects of the Boardman to Hemmingway (B2H) project.

Greenlink

In addressing the issue of experiencing transmission congestion blocking Idaho Power's access to market hubs, the Company has demonstrated that it is investigating the feasibility of securing firm capacity on third-party transmission lines throughout Appendix D of its 2021 IRP. However, Staff expressed concerns in our Comments about the lack of comprehensive analysis of how transmission congestion may change due to other new transmission projects planned outside the Company's balancing area that could provide opportunities for firm transmission.[41] In particular, Staff emphasized that Idaho Power should describe the impact the approved NVE Greenlink Project could have on relieving the congestion south of Valmy.

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[38] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 96, June 15, 2022.
[39] See Docket No. LC 78, Idaho Power Company, Response to OPUC IR 96, June 15, 2022.
[40] See Docket No. LC 78, Idaho Power Company, Reply Comments, August 4, 2022, p 57.
[41] See Docket No. LC 78, Staff's Opening Comments, filed July 7, 2022, pages 23-24.

In Reply Comments, Idaho Power provides a table of all the regional transmission projects and whether they provide firm access to market hubs or not.[42] In elaborating on the table entries, Idaho Power briefly mentions potential opportunities to access southern market hubs via the SWIP-North and NVE Greenlink transmission projects. IPC also adds that the Company would continue to monitor transmission opportunities in Nevada and perform more detailed evaluation of the SWIP-North project. In the 2023 IRP, Staff would like to be able to understand the impact of the Greenlink transmission projects on congestion between Idaho Power's service territory and southern wholesale energy markets.

Staff Recommendation 3: The Company study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets in the 2023 IRP.

Gateway West

CUB notes that Gateway West is not selected in the Preferred Portfolio despite the selection of 700 MW of new wind and 1,405 MW of new solar resources added to its transmission system east of the Treasure Valley.[43] CUB is concerned that any delay in the Valmy or Bridger exit would result in a need for Gateway West in earlier years. Based on this, CUB requests a scenario in which transmission capacity gains from both Valmy and Bridger exits together are not realized.[44]

The Company pledges to continue studying differing exit scenarios for the Bridger units along with other triggers for Gateway West segments in future IRP cycles. To mitigate CUB's concern, the Company states that should a transmission capacity need arise, the line could be constructed relatively quickly as much of the federal permitting for siting has already been completed.[45] Staff supports CUB's inquiry and thanks Idaho Power for taking up this sensitivity request from CUB.

Transmission Availability and Capacity Benefit Margin

In Comments, CUB identifies the loss of transmission availability as one of the driving factors behind the Company's imminent capacity deficiency. Specifically, IPC assumes a reduced transmission availability of 710 MW from the earlier 900 MW for the years 2022-2025.[46] CUB notes that although IPC provided information around the updated assumption of 710 MW, this could be complemented with information explaining the *difference* from the previous assumption. Consequently, CUB is interested in knowing the specific sources of congestion that

[42] See Docket No. LC 78, Idaho Power Company's reply comments, filed on August 4, 2022, Table 4, page 34.
[43] See Docket No. LC 78, CUB, Opening Comments, July 7, 2022, p 9.
[44] See Docket No. LC 78, CUB, Opening Comments, July 7, 2022, p 10.
[45] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 55.
[46] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 3.

contributed to the loss of the 190 MW to assess transmission availability more accurately.[47] CUB also notes that of the 710 MW of transmission availability, 330 MW are reserved for emergency transmission through the Capacity Benefit Margin (CBM). CUB is concerned that IPC does not provide sufficient information on what ensures this CBM availability in the 2022-2025 timeframe and that relying on a significant portion of future transmission from CBM on an emergency basis places a significant level of risk onto consumers.

In Reply Comments, the Company provides a table quantifying the differences in transmission capacity assumptions between the 2019 and 2021 IRPs. The key change in available capacity between the 2019 IRP and 2021 IRP is the Idaho-Nevada transmission capacity. Specifically, in the 2019 IRP, the Company assumed that generation from North Valmy could be replaced by market purchases. However, the Valmy Unit 2 Exit Analysis performed by the Company early in 2021 tested this assumption and found that the necessary transmission is not available, resulting in the 229 MW reduction in available capacity for market purchases for that pathway in the 2021 IRP.[48] The Idaho-Northwest capacity was increased due to the Company's updated network customer load forecast, a load forecast for transmission customers, meaning the Company forecasts a decrease in congestion in this path. The reduction in Idaho-Montana capacity was explained by a lack of available third-party firm capacity. The 2021 IRP also includes an existing 50 MW reservation from Red Butte to Borah across the PacifiCorp East system that was not included in the 2019 IRP and provides access to the southern market hub at Mead.

In response to CUB's concern about the availability of CBM, the Company provides an example of how non-firm path schedules of other entities could be cut in the case of an energy emergency to free up transmission for Idaho Power to access market energy. Still, the Company recognizes that there is risk associated with assuming third-party transmission will be available for CBM and states that they expect that WRAP will provide an opportunity to adjust IRP-related CBM assumptions in the 2023 IRP.

STOP expresses frustration about the loss in transmission availability that IPC is experiencing compared to the 2019 IRP, as well as the Company's actions to prevent or address this. STOP notes that the transmission scenarios have become more complex in this IRP and made several requests for additional information about actions that could alleviate the situation.[49] Specifically, STOP requests information about the use of the 200 MW of import capacity (acquired from PAC) for summer peaking months, the new use of CBM and Transmission Reliability Margin (TRM) to serve load, as well as the impact of reducing the reliability threshold from 0.1 to 0.05 days per year.[50] STOP requests that the Company perform continued assessment of all markets for energy and capacity, not just Mid-C, the reinforcement of Borah West and Midpoint West, the utilization of Gateway West transmission rights, building Idaho Power Segments Phase 1 & 2, and examining SWIP-North.

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[47] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 4.
[48] Idaho Power Company's Reply Comments, at 49.
[49] Idaho Power Company's Reply Comments, at 9-10.
[50] Idaho Power Company's Reply Comments, at 9-10.

In Reply Comments, the Company:

- states that the additional import capacity (acquired from PAC) was set to 0 in the summer peaking months to reflect a conservative planning approach. However, rather than consider Four Corners as providing no benefit in the summer, the Company looks at Four Corners as providing a summer capacity market hedge;
- argues that the treatment of the CBM and TRM are identical to the 2019 IRP, and
- disagrees about the lack of new information on the impacts of changing the reliability threshold from 0.1 to 0.05 and provides the associated cost;
- commits to continue to study all available energy market opportunities. Explains that Borah West and Midpoint West upgrades were included as part of the 2022 B2H Term Sheet; and
- states the Company will continue to evaluate Gateway West transmission projects in future IRPs. And IPC plans to perform a more detailed evaluation of SWIP-North in future IRPs.

Boardman to Hemmingway (B2H) Project

Projected revenues from B2H

In the 2019 IRP, Idaho Power specified the transfer capacities and permitting cost allocation percentage for each party in the three-way joint funding agreement between PacifiCorp, BPA, and Idaho Power.[51] In the 2021 IRP, Idaho Power described the B2H development risk under the new arrangement of the Company assuming BPA's previous 24 percent ownership share in B2H, in addition to Idaho Power's previous 21 percent ownership, as per the term sheet.[52] Under the new terms, Idaho Power will fund 45 percent of B2H project development costs while BPA will pay Idaho Power for the transmission service provided to BPA's customers across southern Idaho through network integration transmission service agreements (NITSA) under Idaho Power's open access transmission tariff OATT rather than continue to pay 24 percent of the development costs. The Company presented this larger share of ownership as having no incremental cost to Idaho Power's ratepayers, because wheeling revenue from BPA will cover the new costs. Staff has focused on confirming whether that new revenue can be expected to cover the new costs.

[51] See Docket No. LC 74, Idaho Power, Second Amended IRP, January 31, 2020, p 69.
[52] See Docket No. LC 78, Idaho Power, IRP, Appendix D, February 16, 2022, pp 6-7.

In its response to OPUC IR 82 regarding the balance of revenue and cost of the extra investment in the B2H project, the Company demonstrated how BPA's transmission service payments to Idaho Power under the NITSAs will offset Idaho Power's costs associated with BPA's usage of the B2H project over time. In support of this claim, the Company presented two spreadsheets; one representing the net present value (NPV) of BPA payments to Idaho Power for transmission services under the OATT, and the other representing the NPV of the incremental costs associated with acquiring BPA's share of the B2H project. Both NPVs were calculated for 55 years.

In Comments, Staff sought more details behind the forecast of revenue from BPA, the key parameters used in the OATT to determine wheeling payments.[53] In Reply Comments, the Company explained how it modelled 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.[54]

To understand how the BPA payments are sensitive to the projected BPA load to be transmitted via B2H, Staff issued OPUC IR 126 asking the Company to provide the impact on the projected BPA revenues from the forecasted high and low peak load (MW) and energy transfer (MWh), as the charges calculated in Schedule 9 of the OATT depend on those two key components.[55] The Company's response to OPUC IRs 82 and 126 show that under a low scenario of only 0.55 percent load growth, BPA's revenue could **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Staff finds this to be a reasonable risk, assuming the forecast of B2H costs are accurate. Also, B2H will have excess capacity, particularly from east to west. In response to OPUC IR 127, Idaho Power states that the Company has not included any additional wheeling revenue from B2H beyond that from BPA in Idaho Power's comparison of incremental B2H costs to incremental transmission revenue.

In Comments, STOP makes a similar call for more transparency of forecasted wheeling revenue as Staff made in our Comments. Those Comments were made before the Company's responses to OPUC IRs 126 and 127. Staff looks forward to reading any analysis of Idaho Power's revenue assumptions STOP may provide in Final Comments.

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[53] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, Staff Request 19, page 23.
[54] See Docket No. LC 78, Idaho Power, Reply comments, August 4, 2022, page 31.
[55] See Schedule 9 Information at https://www.idahopower.com/accounts-service/understand-your-bill/pricing/idaho-pricing/business/schedule-9-information/#:~:text=Who%20Is%20a%20Schedule%209,recent%2012%20consecutive%20Billing%20Periods, website viewed on August 22, 2022.

Project costs

While the Company's responses to OPUC IRs 126 and 127 confirm for Staff that the Company is not basing its analysis on rosy assumptions of new wheeling revenue, we do not have the same level of confidence that B2H costs estimates have avoided underestimation. STOP's arguments about how the B2H cost estimates remain preliminary in detail and unadjusted for inflation appear valid to Staff

STOP raises concern that the B2H budgets for 2016 and 2021 are too close in number considering inflation, pandemic, supply chain issues, and additional substation and transmission reinforcements that were not mentioned in previous IRPs.[56] Furthermore, STOP notes that no documentation has been provided for the budget reflecting the increased ownership share. STOP finds that the budget is outdated, contains inconsistencies, is not adjusted for inflation, and reflects a 50 percent or higher probability to be exceeded.[57] STOP states the Company based its estimate on the "preliminary design" which would land the estimate to a 3 or 4 estimate class under the Association for the Advancement of Cost Engineering (AACE) guideline which means that there is a 50 percent or less probability that the budget will be as projected.[58] Therefore, STOP is requesting the Commission direct Staff and/or a consultant to conduct a more thorough analysis of the B2H budget within this IRP cycle.[59]

In Reply Comments, Idaho Power disagrees that the budget is a stale forecast and states that updated estimates reflecting the increased ownership share have been provided in the Company's response to STOP B2H's IR 4. Furthermore, although the 2021 IRP was developed prior to major inflation, labor, and supply chain issues experienced over more recent months, the Company argues that competing technologies are subject to the same issues.[60] The Company denies the existence of any inconsistencies and argues that the full cost of delivering power to the Idaho Power network (including wheeling charges) is considered in the analysis, while wheeling revenues received by the Company for delivering power across the system for third parties apply as a credit to the Company's rate base calculations.

Staff agrees with STOP, that Idaho Power's original construction cost estimates for B2H are getting stale. However, the Company has modeled the 2021 IRP using B2H cost contingencies. The uncertainty of B2H's cost falls within the cost contingencies we recommended in the 2019 IRP. Staff is comfortable that Idaho Power's proposed Action Item related to B2H is adequately supported by Idaho Power's IRP analysis.

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[56] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 4.
[57] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 5.
[58] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 5.
[59] See Docket No. LC 78, STOP, Opening Comments, July 7, 2022, p 8.
[60] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 65.

In the 2023 IRP, a more rigorous update of B2H cost will be required along with a 30 percent contingency modeled off that updated cost estimate. With the complex nature of the current B2H Term Sheet's assets swaps, upgrades, and actual cost responsibility, Staff will seek a more comprehensive understanding of the details of costs included in any 2023 IRP portfolio including the B2H project and how these costs have changed from the 2021 IRP.

B2H's total cost should be disaggregated by component and the math behind estimating each component cost presented to the public. The Company should identify the breakdown of elements of costs that make up the total cost (e.g. the costs associated with transmission towers' construction, poles, wires, infrastructure, auxiliary equipment, right of way, permitting, etc.) and include all assumptions to come up with the cost estimate.

In Comments, Staff inquired on the possibility of PacifiCorp seeking the same deal as BPA of relying on paying transmission charges based on OATT rates instead of bearing the risk of ownership.[61] Staff requested that the Company describe the probability of Idaho Power ownership share of B2H increasing again. In Reply Comments, Idaho Power claims that the probability is low, given PacifiCorp's commitment to the project in its own 2021 IRP. In the contingency of the low probability event of PacifiCorp electing not to move forward with the B2H project, Idaho Power said it would reevaluate its options and likely seek a replacement partner and that a 100 per cent ownership was very unlikely.[62]

Staff Recommendation 4: For the 2023 IRP, produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate.

Federal grant funding

Based on the major objective for the Commission to reduce the cost of the B2H project on ratepayers, Staff wants to ensure that Idaho Power explored all possible avenues of grant funding. After the Company's initial response to OPUC IR 1 indicating that Idaho Power had not sought federal grant funding for B2H, Staff followed up in Comments by providing examples of available transmission funding under the November 2021 Infrastructure Investment and Jobs Act (IIJA).[63] On this basis, Staff asked the Company for the reason why Idaho Power had not sought external funding.[64]

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[61] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 5.
[62] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 31.
[63] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 23.
[64] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 23.

In Reply Comments, the Company pointed out that the solicitation window for applicants to submit projects for grant money under the IIJA had not opened and that it would be monitoring that space. Idaho Power states the B2H project would unlikely qualify for those funds due to the high percentage of prescribed capacity in the negotiated term sheet of the project.[65] Staff recommends the Company's document its monitoring of grant funding in its reports to Docket No. RE 136.

Staff Recommendation 5: Document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including in each report:

a. **Identification of what federal funding and guarantees B2H potentially qualifies for under current and emerging law and programs**
b. **An explanation of what is required for the Company to apply for that funding or guarantee**
c. **An explanation of whether the Company is preparing an application or grant request at the time of reporting. If the Company is not preparing an application, explain why.**

Forecasting Qualifying Facilities (QF)

REC recommends that the Commission acknowledge Idaho Power's planning assumptions that 100 percent of existing non-wind QFs will renew after contract expiration as it allows Idaho Power to defer resource acquisition and sets reasonable avoided cost prices in Oregon.[66] REC also recommends that the Commission acknowledge Idaho Power's assumption that 25 percent of existing wind QFs will renew after contract expiration.[67] However, REC believes that the actual renewal rate for existing wind QFs will be higher than 25 percent. In future IRPs, REC recommends that the useful life of utility and non-utility-owned facilities is evaluated to determine the renewal rate.

In Reply Comments, the Company notes that it plans to re-visit the topic of QF renewal assumptions in the next IRP. Staff supports REC's request for a more empirical basis for assuming QF contract renewal and thanks the Company for agreeing to look more closely at the basis for these renewal assumptions.

The 2021 IRP unreasonably assumes no future QFs will emerge beyond those already contracted. Building B2H can be expected to create new opportunities for QFs in eastern

[65] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 33.
[66] See Docket No. LC 78, REC, Opening Comments, July 7, 2022, p 2.
[67] See Docket No. LC 78, REC, Opening Comments, July 7, 2022, p 2.

Oregon, and Idaho Power has not defended its assumption with evidence. Instead, the Company defends its assumption of zero new future QFs by stating that it "is based on the sound principle that long-term planning cannot be based on speculative decisions that are beyond the Company's control."[68] That is a false distinction, because every assumption an electric company makes in an IRP involves a speculative decision that is beyond its control. For example, the 2021 IRP speculates on the policy risk to the Company's hydro generation, that: "No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2021 IRP."[69] If the Company's speculation about future hydro operations is wrong, then Idaho Power will be significantly underestimating the Company's long-term need for new resources. The need for speculation cannot be avoided in resource planning. However, unreasonable assumptions can be avoided. To avoid the unreasonable assumption that no QFs will emerge in the next twenty years, the Company should forecast future QFs in the next IRP.

Staff Recommendation 6: For the 2023 IRP, assume zero new QFs only in the first four years of the planning horizon. Starting in the fifth year, use a reasonable forecast of new QF resources for the rest of the planning horizon.

Modeling Reliability

Idaho Power models reliability independently from Aurora using MATLAB to estimate resource ELCC and system LOLE as prescribed by Roy Billinton and Ronald Allan's 1984 *Reliability Evaluation of Power Systems*. Staff met twice with Idaho Power to go over the MATLAB scripts. Staff's review of Idaho Power' use of MATLAB in the 2021 IRP was sufficient to confirm that Idaho Power is following an established method of modeling system reliability.

Staff finds no fault with the Company's calculations of ELCC or LOLE. Idaho Power has made a good faith effort to become compliant with Order No. 16-326's guidelines for estimating VER capacity contribution. Relatively low ELCCs for wind resources may plausibly be explained by the Company's summer peak, which may continue to run earlier than other utilities' summer peaks. Staff has not had sufficient time to fully reproduce Idaho Power's system LOLE modeling and consider all modeling choices. Staff plans to focus more time on this in our review of Idaho Power's 2023 IRP, working in coordination with the staff of the Idaho Public Utilities Commission (IPUC Staff). Staff notes that IPUC Staff has concern about Idaho Power's change in reliability standard, insufficient incorporation of extreme weather events, and the Company's use of only one year (2023) as the basis for calculating the planning reserve margin for the entire 20-year planning horizon.[70] Getting reliability estimates right will be critical as the

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[68] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 37.
[69] See Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p 19.
[70] See Case No. IPC-E-21-43, IPUC Staff, Comments, June 2, 2022, p 4.

Company procures more VERs, and from Staff's meeting with the Company, we believe Idaho Power is keenly aware of this.

Recognizing the importance of the 2021 IRP's imminent capacity deficit, Renewable Northwest comments on the resource adequacy and reliability assessment of the modeled portfolio. Although Renewable Northwest does not state a specific preference on the Company's modeled reliability threshold, they highlight the importance of an accurate assessment recommending that the Company consults with the NWPCC and the Resource Adequacy Advisory Committee (RAAC) to ensure that correct definitions and methodologies are being used.[71] Renewable Northwest further recommends that the Company works with NWPCC to develop datasets for temperature and stream flow that better reflect the impacts on hydropower generation and overall resource adequacy.

The Company confirms that they have reviewed the 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 notes it will continue to engage with Renewable Northwest, the NWPCC, and the RAAC to ensure that correct definitions and methodologies are being used to conduct resource adequacy assessments.[72]

In Comments, Renewable Northwest recommends the use of the ELCC method for all supply-side resources, highlighting that there is considerable risk in applying the methodology only for calculating the capacity contribution of renewable and energy-limited resources, but not thermal resources. Renewable Northwest noted that portfolio modeling incorrectly assumed that gas-powered power plants have capacity values of over 90 percent.[73] This may be an overestimate of the capacity value of gas power plants with the actual ELCC being around 85 percent at best.

In Reply Comments, Idaho Power recognizes Renewable Northwest's concerns but clarifies that the 2021 IRP included thermal derates due to weather-related conditions on top of fixed equivalent forced outage rates (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.[74]

Aside from how Idaho Power calculates reliability, Staff has found an issue in how the Company's reliability standard is applied. The preferred portfolio does not meet the Company's reliability standard for all twenty years in the planning horizon. Or maybe it does by procuring a SCCT pant. Or maybe no gas plant will be acquired, because, the Company states: "For the 2021 IRP, a SCCT cost was added because it is a flexible resource with a high ELCC that allowed for a

[71] See Docket No. LC 78, Renewable Northwest, Opening Comments, July 7, 2022, p 6.
[72] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 63.
[73] See Docket No. LC 78, Renewable Northwest, Opening Comments, July 7, 2022, p 6.
[74] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 62.

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."[75] So, the gas plan is just a proxy for some unknown resource that will be necessary to meet the reliability standard but was not included in the preferred portfolio. Staff is surprised by this ambiguity around basic questions of reliability and resource selection, core aspects of an IRP.

The 2021 IRP is only compliant with the requirements of Order No. 07-002 if the preferred portfolio is assumed to contain the procurement of a SCCT plant by 2037. Yet the preferred portfolio contains no such planned acquisition. Instead, a monetary penalty was applied to portfolios that failed to meet the Company's reliability standard for the entire 20-year planning period. So, either Idaho Power appears to fail to minimize risk, or the Company appears to fail to plan for the minimum required 20 years.

In Reply Comments, Idaho Power seems to imply that the time horizon of its reliability planning is just the Action Plan:

> 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.[76]

While placing greater scrutiny in the Action Plan years is understandable, failing to plan for resources in the last few years of the planning horizon is not. While actual resources may change as 2037 inches closer to an Action Plan, what resources the Company acquires in the near term may impose path-dependency on resource optimization later. Trouble meeting the reliability standard in later years may be an indication that the resource path the Action Plan embarks upon is not optimal in the long term.

[75] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 40.
[76] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 40.

Idaho Power is trying to use the SCCT as a cost-penalty to compare portfolios for 20-year cost optimization but is not accurately doing that for two reasons. First, the Company is not imposing the total cost of a SCCT, only the capital costs. This misses O&M, fuel, and the cost of carbon. Second, when trying to monetize the expected cost of a loss of load, the cost will not be what the Company could have procured to prevent rolling blackouts. The expected cost would be the economic cost of the blackouts.

This might primarily be a computational issue that can be overcome by software solutions. When Staff met with the Company to discuss LOLE on August 23, 2022, Idaho Power described computational challenges modeling past sixteen years due to the diminishing marginal capacity contributions of resources. If the cause of the computational struggle is grounded in declining ELCCs, then the modeling challenges might be mimicking true dispatch challenges of the future. For this reason, fully planning for the resources necessary to meet the Company's reliability standard for twenty years, given what we know now, will offer important insights on reliability, even if we all expect significant technological change by the end of the 2030s. For the 2023 IRP, Staff recommends the Company avoid using Aurora's unserved energy function either as a proxy resource for an unknown future technology or as a financial penalty for a portfolio failing to meet the Company's reliability standard. Instead the Company should include all the necessary resources in the portfolio to meet the Company's reliability standard for a minimum of twenty years.

Staff Recommendation 7: For portfolios considered for selection as the preferred portfolio in the 2023 IRP, include all the necessary resources to meet the Company's reliability standard for a minimum of twenty years.

Twenty-Year Limit to Costs

Staff finds no fault with Idaho Power's limit of the consideration of costs to 20 years. The Company levelizes the NPV of the full lifecycle costs of a resource into an annual cost. When scoring portfolios, the only costs that are included are the annual costs incurred during the 20-year planning horizon. This may bias capital intensive assets with long useful lives, or as the Company points out, it may not entail a bias, if shorter-lived assets were continuously procured out to the time frame of a long-term asset like B2H. The Company's approach to levelizing the cost of assets with useful lives greater than twenty years offers a reasonable solution to this analytic problem.

Resource Retirement and Decommissioning Costs

Idaho Power does not allow Aurora to consider the retirement of every resource. The 2021 IRP only models the early retirement of coal resources. Idaho Power offers both an unpersuasive and a persuasive reason for this. The unpersuasive reason is that the early retirement of resources "runs counter to actual energy system investment and operations."[77] The Company goes on to position coal as an exception: "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." Staff understands that electric companies prefer not to retire resources early. The early retirement of coal resources also once ran counter to actual energy system investment and operations until mounting stakeholder pressure highlighted the evidence that some plants are uneconomic to run for their full useful lives. Given the dynamic trends in technological change, resource planning should proactively identify resource obsolescence in advance of previously planned retirement dates.

However, Idaho Power also provides a persuasive reason for why the 2021 IRP only models the early retirement of coal plants: "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."[78] Without data on retirement costs, the Company would not be able to add this granularity to the modeling. The Company pledges "to consider this issue further in the 2023 IRP." Staff thanks Idaho Power for considering how to collect this data and incorporate it into portfolio modeling.

Battery Storage Capital Cost

[BEGIN HIGHLY CONFIDENTIAL] [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]** Staff considers documented bids as good a source of cost information, if not better than, publicly available research published by sources like NREL or Lazard.

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[77] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 38.
[78] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 38.

Other Issues Raised by Stakeholders

Resource Procurement

Renewable Northwest highlights several advantages of power purchase agreements (PPA) as an alternative to utility-owned resources.[79] The Comments focus on the mitigation of operational risks. Renewable Northwest states that developers have a significant level of expertise in product development, testing, and simulations and utilities could hedge operational risks using fixed energy or capacity contracts. Other advantages include battery cell replacements, the ability to navigate tax incentives effectively, reduction in decommissioning costs, and others. Based on the above, 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.[80]

Idaho Power acknowledges Renewable Northwest's concerns and recommendations but states that they already consider all ownership arrangements in the resource procurement process. As an example, in its most recent RFP, Idaho Power solicited bids for both PPA and non-PPA ownership arrangements. Regardless, the Company notes that a lack of previous battery storage experience/ownership should not preclude a utility from acquiring battery storage resources under an ownership arrangement.[81]

Resource Options

Renewable Northwest recommends that for the 2023 IRP, the Company consider a wide variety of supply-side resources including long-duration batteries and other mediums to long-duration storage technologies, especially focusing on the 6 to 12-hour storage range.[82] In addition to these resources, Renewable Northwest also recommends that in the 2023 IRP the Company models multiple configurations of hybrid resources, including solar and wind paired with energy storage systems of different durations.

The Company agrees with Renewable Northwest's recommendations to model multiple configurations of solar plus storage in the 2023 IRP, including longer-duration battery storage. It notes that four- and eight-hour storage options were included in the 2021 IRP analysis and are part of the preferred portfolio.[83] The Company stated that hybrid resources will continue to be evaluated in the 2023 IRP.

Bridger Gas Conversion

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[79] See Docket No. LC 78, Renewable Northwest, July 7, 2022, p 6.
[80] See Docket No. LC 78, Renewable Northwest, July 7, 2022, p 7.
[81] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 63.
[82] See Docket No. LC 78, Renewable Northwest, July 7, 2022, p 3.
[83] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 61.

Idaho Power intends to partner with PacifiCorp in the conversion of Jim Bridger Units 1 & 2 from coal to gas-fired generation resources in 2024 with 2037 retirements. Stemming from Renewable Northwest's belief that the capacity contribution of gas resources is overstated due to not applying the ELCC methodology to thermal assets, as well as skepticism of Idaho Power's assumed of gas prices, Renewable Northwest recommends that Idaho Power reconsider investing in coal to the gas conversion of the Bridger units in favor of cost-effective and reliable hybrid and standalone storage resources.[84]

In Reply Comments, the Company states Idaho Power 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. Furthermore, the Company states that based on analysis with updated gas forecasts as of June 2022, the unit conversions remain part of the least cost portfolio. The 2023 IRP process will continue to evaluate resource selections incorporating the recent gas price volatility as well as stakeholder feedback from the 2021 IRP Advisory Committee.

Hells Canyon Relicensing

CUB believes that additional analysis is needed to understand the costs and benefits of the Hells Canyon Complex (HCC) relicensing and poses the question of whether customers can save money by diverting Company resources from relicensing efforts to more productive areas.[85]

The Company highlights the importance of HCC in meeting the energy, capacity, and ancillary services requirements of their system, especially as the Company transitions away from coal and towards a portfolio with increasing renewable generation. According to the Company, the most likely replacement would be a combination of simple cycle and combined cycle natural gas turbines, resulting in increased costs, emissions, and risks for ratepayers. Therefore, the Company believes that the use of Company resources in the relicensing effort of the HCC is a prudent investment and resource strategy.

[84] See Docket No. LC 78, Renewable Northwest, Opening Comments, July 7, 2022, pp 4-5.
[85] See Docket No. LC 78, CUB, Opening Comments, July 7, 2022, p 14.

Emissions

Emissions of Market Purchases/Sales

In Comments, Staff requested an updated emissions forecast that included emissions from market purchases. Idaho Power and Staff then conversed regarding this topic, and in Reply Comments, Idaho Power included two updated emissions forecasts using 1) a default market emissions factor and 2) a calculated monthly zonal emissions rate.

Staff appreciates the Company's work on this forecast and finds that the method of including emissions from market purchases while removing emissions from market sales is reasonable. Staff finds that having access to both forecasts is helpful in the 2021 IRP, and in future IRPs there may be further discussion on which methodology is most useful for review of IPC's emissions forecasts.

2021 Emissions

In Comments, Staff requested Idaho Power provide an emissions forecast for 2021 using 2021 IRP assumptions and 2021 hydro conditions. In Reply Comments, Idaho Power wrote that it is "unable to perform the requested analysis…" and that actual emissions will differ from Aurora's modeled emissions since the IRP model is not intended to perfectly capture daily operations. Beyond specific changes in modeling the 2021 IRP to test the reasonableness of the Action Plan, Staff does not intend to further ask the Company to perform an additional model run for 2021 in order to demonstrate the accuracy of its emissions modeling. Capturing large trends in emissions may be sufficient, and the Company has reasonably accomplished that in Reply Comments.

Instead of an additional model run in this IRP, Staff requests that the Company, in the executive summary of its next IRP, provide a graph showing its GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.

Staff Recommendation 8: In the executive summary of the Company's 2023 IRP, provide a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.

Clean Energy Goal

In Comments, Staff requested the Company make its external messaging on emissions consistent with Idaho Power's actual resource planning. Staff wrote, "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. The preferred portfolio reduces emissions only 41 percent from 2021 to 2040."[86] In Reply Comments, Idaho Power wrote that the Company's goal of reaching 100 percent clean energy by 2045 depends on advancement of clean energy technologies and cost reductions, as well as construction of the B2H transmission line.[87]

Staff finds that the Company's response does not address why the technology advances and cost reductions mentioned cannot be modeled in the IRP. Cost reduction curves for new technologies consistent with estimates from national laboratories or those of a third-party consultant can be included in an IRP's model. The emissions impact associated with the introduction of B2H into the portfolio should be included in the IRP modeling results by default. Staff will continue observing Idaho Power's progress toward its 2045 goal. Additionally, Staff will review Idaho Power's advertising expenditures in the next rate case with a focus on whether the Company's clean energy goal is being used in advertising in a way that is misleading to customers, given that the Company's actual long-term plans do not meet the goal.

Conclusion

This concludes Staff's final comments for Idaho Power's 2021 IRP. Here is a summary of our recommendations:

1. The Company rerun its Aurora modeling by updating:
    a. The nameplate of existing DR to what was observed in 2022,
    b. The endogenous wholesale price forecast with an exogenous entry of historical prices and current futures prices,
    c. The capital cost of a CCCT plant with $1,300 per kW or an observed capital cost from an RFP bid,
    d. The ITC for solar and battery storage (including standalone storage) at the 30 percent level through 2032,
    e. The PTC for wind at the 1.5 cents/kWh level through 2032,
    f. And extend both the ITC and PTC for nuclear and green hydrogen from 2025 through 2032.

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[86] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2022, p 30.
[87] See Docket No. LC 78, Idaho Power, Reply Comments, August 4, 2022, p 47.

After completing this modeling update, present the results in the Company's Reply Comments and detail how it impacts the 2021 Action Plan.

2. The Company model new DR for the 2023 IRP based on the results of the Idaho Power-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.
3. The Company study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets in the 2023 IRP.
4. For the 2023 IRP, produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate.
5. Document the Company’s monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including in each report:
    a. Identification of what federal funding and guarantees B2H potentially qualifies for under current and emerging law and programs
    b. An explanation of what is required for the Company to apply for that funding or guarantee
    c. An explanation of whether the Company is preparing an application or grant request at the time of reporting. If the Company is not preparing an application, explain why.
6. For the 2023 IRP, assume zero new QFs only in the first four years of the planning horizon. Starting in the fifth year, use a reasonable forecast of new QF resources.
7. For portfolios considered for selection as the preferred portfolio in the 2023 IRP, include the necessary resources to meet the Company’s reliability standard for a minimum of twenty years.
8. In the executive summary of the Company’s 2023 IRP, provide a graph showing Idaho Power’s GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.

Dated at Salem, Oregon, this 8th of September, 2022.

Eric Shierman

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