An IDACORP Company

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February 16, 2022

VIA ELECTRONIC EMAIL

Jan Noriyuki, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-21-43
Idaho Power Company's 2021 Integrated Resource Plan Appendix D and Errata

Dear Ms. Noriyuki:

Attached for electronic filing is Appendix D to Idaho Power Company's (Idaho Power or Company) 2021 Integrated Resource Plan (IRP), which the Company had stated would be filed in the first quarter of 2022. Additionally, the Company submits for electronic filing eight (8) replacement pages with corrected portfolio cost information. As explained and demonstrated below, these portfolio cost updates are immaterial in nature, do not impact the selection of the Preferred Portfolio, and do not adjust any of the portfolio rankings in the 2021 IRP.

Appendix D

Appendix D of Idaho Power's 2021 IRP includes updates on the Boardman to Hemingway (B2H) project, including explanation of the finalized term sheet signed by Idaho Power, PacifiCorp, and Bonneville Power Administration. Idaho Power previously filed the term sheet in this docket on January 19, 2022.

In addition to updates and analysis related to the B2H project, Appendix D provides information on Idaho Power's transmission system, how it is modeled in the IRP, and the modeling and status of other potential transmission projects, such as Gateway West.

Replacement Pages

In addition to Appendix D, Idaho Power is filing eight (8) replacement pages to the main 2021 IRP report. In the process of organizing IRP data files during completion of Appendix D, Idaho Power identified two separate data discrepancies related to Bridger Plant cost estimates. These updates result in immaterial cost changes to portfolios in the 2021 IRP.

The first data issue arose because of the timing of revised estimates received by the Company for costs related to the early exit of the Bridger Plant units. Idaho Power continued to receive updated cost estimates throughout December 2021. To determine portfolio costs in the IRP, Idaho Power inadvertently used the penultimate set of cost estimates rather than the final cost estimates. For portfolios in which any of the Bridger units are exited before end of book life, the revised costs increase the net present value (NPV) of portfolios by between $4 and $6 million—an increase of between 0.041 percent to 0.077 percent. This portfolio cost increase is de minimis in relation to total portfolio costs of approximately $8 billion, and does not change the selection of the Preferred Portfolio, nor does it change any of the portfolio rankings or sensitivity outcomes.

The second data issue, related to cost estimates for the Bridger Plant natural gas conversion, was due to the inadvertent exclusion of fixed operations and maintenance (O&M) costs associated with the conversion in IRP portfolio cost development. The IRP planning team believed these costs were accounted for in Idaho Power's internal finance (p-worth) model. However, due to the newness of Bridger Plant conversion discussions, this cost stream had not yet been incorporated into the p-worth. These fixed O&M costs add between approximately $12-23 million to total NPV portfolio costs in the IRP—a cost increase of between 0.2 percent to 0.3 percent to portfolios and sensitivities in which either unit 1 or 2 is converted to natural gas. Similar to the issue above, this increase is immaterial to the IRP analysis, does not change the selection of the Preferred Portfolio, and has no impact on portfolio rankings or sensitivity outcomes.

Combined, these corrected data issues result in NPV portfolio cost increases of between $5 million and $29 million on total NPV portfolio costs of approximately $8 billion—an increase of *less than half of 1 percent* on affected portfolios. The table below compares the NPV of a selection of portfolio costs as originally published compared to the amended amounts included in the replacement pages. As the table demonstrates, the portfolio cost increases resulting from these two issues do not change any aspect of Preferred Portfolio selection or portfolio rankings.

2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	ORIGINAL Planning Gas, Planning Carbon	UPDATED Planning Gas, Planning Carbon	Total Percentage Increase
Base with B2H	$7,915,702	$7,942,428	0.34%
Base B2H PAC Bridger Alignment	$7,999,347	$8,021,906	0.28%
Base without B2H	$8,192,830	$8,219,281	0.32%
Base without B2H without Gateway West	$8,441,414	$8,470,101	0.34%
Base without B2H PAC Bridger Alignment	$8,185,334	$8,207,893	0.28%
Base with B2H—High Gas High Carbon Test	$7,997,339	$8,024,064	0.33%

Idaho Power is committed to identifying and correcting issues in a straightforward and transparent manner. To this end, the Company provides this update to ensure the Commission and stakeholders are operating with the latest and most accurate information. Idaho Power believes its thorough quality control process brought to light these minor issues and allowed for a timely correction.

If you have any questions about the attached documents, please do not hesitate to contact me.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:sg
Attachments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 16th day of February 2022, I served a true and correct copy of Idaho Power Company's 2021 Integrated Resource Plan Appendix D and Errata upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Dayn Hardie Deputy Attorney General Idaho Public Utilities Commission 11331 W. Chinden Blvd., Bldg No. 8, Suite 201-A (83714) PO Box 83720 Boise, ID 83720-0074	______Hand Delivered ______U.S. Mail ______Overnight Mail ______FAX ____ FTP Site _X__Email: Dayn.Hardie@puc.idaho.gov
Idaho Conservation League Benjamin J. Otto Emma E. Sperry Idaho Conservation League 710 N. 6th Street Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX ____ FTP Site _X_EMAIL botto@idahoconservation.org esperry@idahoconservation.org
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Stacy Gust

Stacy Gust, Regulatory Administrative Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-43

IDAHO POWER COMPANY

ATTACHMENT
LEGISLATIVE FORMAT

- Unit 2—Allowed to exit between year-end 2023 and year-end 2026 or convert to natural gas as early as year-end 2023. If converted to natural gas, the unit will operate through 2034.
- Unit 3—Can exit no earlier than year-end 2025 and no later than year-end 2034.
- Unit 4—Can exit no earlier than year-end 2027 and no later than year-end 2034.

The results of the LTCE model indicate that the conversion of units 1 and 2 to natural gas in 2023 is economical. The Preferred Portfolio identifies exits for units 3 and 4 year-end 2025 and 2028, respectively. To ensure the robustness of these modeling outcomes, the company performed a significant number of validation and verification studies around the Bridger conversions and coal exit dates. These validation and verification studies are detailed in Chapter 9.

Boardman to Hemingway

Idaho Power in the 2021 IRP requests acknowledgement of B2H based on the company owning 45% of the project. This ownership share, which represents a change from Idaho Power's 21% share in the 2019 IRP, is the result of negotiations among Idaho Power, PacifiCorp, and Bonneville Power Administration (BPA). Under such a structure, Idaho Power would absorb BPA's previously assumed ownership share in exchange for BPA entering into a transmission service agreement with Idaho Power. This arrangement, along with many other aspects of B2H, will be detailed in *Appendix D*, which will be filed during the first quarter of 2022.

The Preferred Portfolio, which includes B2H, is significantly more cost-effective than the best alternative portfolio that did not include B2H.

- Base with B2H Portfolio NPV (Preferred Portfolio)—$~~7,915.7~~7,942.4 million
- Base without B2H PAC Bridger Alignment Portfolio NPV—$~~8,185.3~~ 8,207.9million
- B2H NPV Cost Effectiveness Differential—$~~269.6~~265.5 million

Under planning conditions, the Base with B2H (Preferred Portfolio) is approximately $~~270~~ 266 million more cost effective than the best portfolio that did not include the B2H project. Detailed portfolio costs can be found in Chapter 10.

This arrangement, along with many other aspects of B2H, will be detailed in the *Appendix D–Transmission Supplement*, which will be filed during the first quarter of 2022.

B2H's value to Idaho Power's customers is substantial, and it is a key least-cost resource.

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Finally, B2H is an important step in moving Idaho Power toward its 2045 clean energy goal. The B2H 500-kV line adds significant regional capacity with some remaining unallocated east-to-west capacity. Additional parties may reduce costs and further optimize the project for all participants.

Project Participants

In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the B2H project. Table 7.2 shows each party's B2H capacity and permitting cost allocation.

Table 7.2 B2H capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350: 200 winter/500 summer	400: 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

For the 2021 IRP, Idaho Power modeled B2H assuming that BPA transitions from an ownership stake in the B2H project to a service-based stake in the project. Further details regarding this assumption will be provided in *Appendix D*, which is anticipated to be filed during the first quarter of 2022. Table 7.3 shows what each party's new B2H capacity allocation would be, given this assumption.

Each of the portfolios designed under the AURORA LTCE process, that are in contention for the Preferred Portfolio, were evaluated through three different hourly simulations shown in Table 10.2.

Table 10.2 AURORA hourly simulations

	Zero Carbon	Planning Carbon	High Carbon
Planning Gas	X	X	
High Gas			X

The three combinations include the planning case scenarios as well as the bookends for natural gas and carbon adder price forecasts.

The purpose of the AURORA hourly simulations is to compare how portfolios perform throughout the 20-year timeframe of the IRP. These simulations include the costs associated with adding generation resources (both supply-side and demand-side) and optimally dispatching the resources to meet the constraints within the model. The results from the three hourly simulations, where only the pricing forecasts were changed, are shown in Table 10.3. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

Table 10.3 2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$~~7,915,702~~7,942,428	$~~7,186,761~~7,213,486	$~~9,832,001~~9,858,726
Base B2H PAC Bridger Alignment	$~~7,999,347~~8,021,906	$~~7,152,955~~7,175,514	$~~9,932,925~~9,955,484
Base without B2H	$~~8,192,830~~8,219,281	$~~7,784,545~~7,810,996	$~~9,474,983~~9,501,435
Base without B2H without Gateway West[35]	$~~8,441,414~~8,470,101	-	-
Base without B2H PAC Bridger Alignment	$~~8,185,334~~8,207,893	$~~7,588,228~~7,610,787	$~~9,652,891~~9,675,450
Base with B2H—High Gas High Carbon Test[36]	$~~7,997,339~~8,024,064	-	$~~9,424,935~~9,451,660

[35] The company did not continue further evaluation of this portfolio beyond planning conditions due to the portfolio's inferior performance (high-cost, poor reliability, and poor emissions performance).

[36] All portfolios were optimized with planning conditions. The "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

This comparison, as well as the stochastic risk analysis applied to these portfolios (see the Stochastic Risk Analysis section of this chapter), indicate the Base with B2H portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio.

The scenarios listed in Table 10.4 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Each was evaluated under planning natural gas and carbon adder forecasts.

Table 10.4 2021 IRP Sensitivities, NPV years 2021–2040 ($ x 1,000)

Sensitivity	Cost
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428
SWIP-North	$~~7,887,562~~7,914,287
CSPP Wind Renewal Low	$~~7,892,585~~7,919,311
CSPP Wind Renewal High	$~~7,926,005~~7,952,730

The validation and verification tests are listed in Table 10.5. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the Action Plan window, to ensure the model was optimizing correctly and to test assumptions. More details on the setup and expected outcome of each test are provided in Chapter 9.

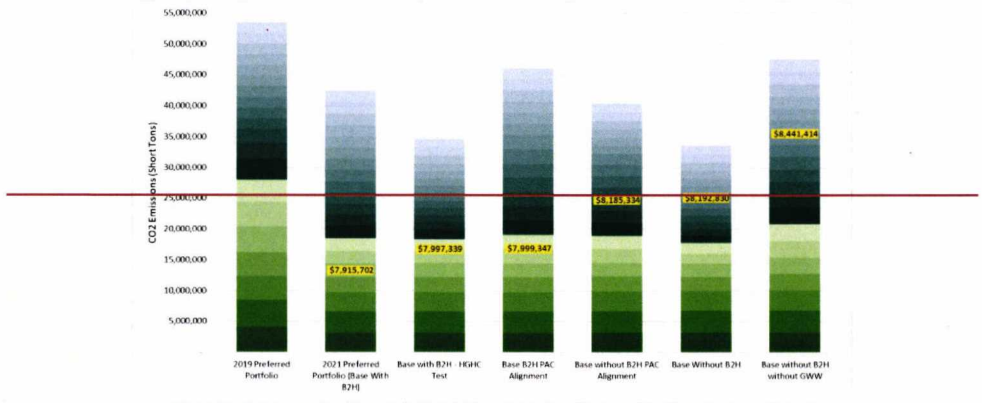
Table 10.5 2021 IRP validation and verification tests, NPV years 2021–2040 ($ x 1,000)

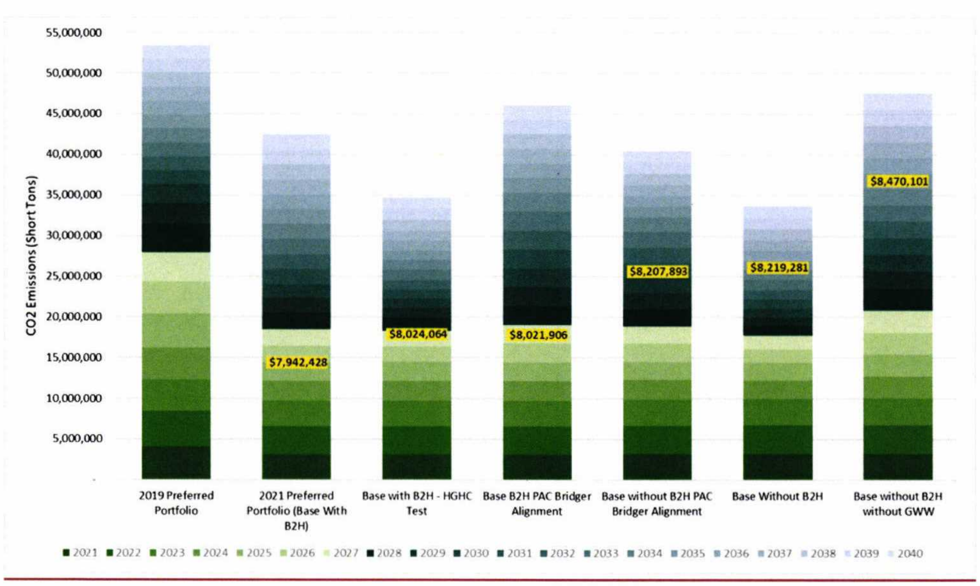
Validation & Verification Tests	Cost
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428
Demand Response	$~~7,917,643~~7,944,368
Energy Efficiency	$~~8,143,113~~8,169,838
Natural Gas in 2028 Rather than Solar and Storage	$~~8,052,194~~8,078,645
Bridger Exit Units 1 & 2 at the End of 2023	$~~8,073,162~~8,077,805
Bridger Exit Unit 2 at the End of 2026	$~~7,997,648~~8,014,305
Bridger Unit 2 Delayed Gas Conversion (2027)	$~~7,938,805~~7,962,665
Bridger Exit Unit 4 in 2027	$~~7,925,427~~7,951,878
Bridger Exit Units 3 and 4 in 2028 and 2030	$~~7,969,378~~7,997,453
Geothermal	$~~7,973,781~~8,000,506
Biomass	$~~7,968,264~~7,994,989
Valmy Unit 2 Exit in 2023	$~~7,930,664~~7,957,116
Valmy Unit 2 Exit in 2024	$~~7,929,939~~7,956,390

Portfolio Emission Results

The company is seeking to execute on the actions identified in the Action Plan window. Therefore, the company evaluated the CO_2 emissions within the Action Plan window for each portfolio in contention for the Preferred Portfolio, along with the SWIP-North portfolio.

Figure 10.2 compares the full 20-year emissions of the company's 2019 Preferred Portfolio to the top contending portfolios in the 2021 IRP. In Figure 10.2, the 2019 Preferred Portfolio is on the far left, adjacent to the 2021 Preferred Portfolio on its immediate right. Compared to the 2019 Preferred Portfolio, the 2021 Preferred Portfolio has cumulative emissions reductions of about 21%. As can be seen on Figure 10.2, the other 2021 portfolios each reflect reduced emissions as compared to the 2019 Preferred Portfolio and are sorted by present value portfolio cost from left to right. The costs associated with each portfolio are shown in the yellow highlights. While 2021 IRP portfolios are shown on Figure 10.1 to have relatively similar emissions output during the Action Plan window, three portfolios have lower projected emissions than the 2021 Preferred Portfolio over the full 20-year planning horizon. However, it is important to note that each of those three portfolios present higher expected cost. The information presented on Figures 10.1 and 10.2 demonstrate that Idaho Power's CO_2 emissions can be expected to trend downward over time. Idaho Power will continue to evaluate resource needs and alternatives that balance cost and risk, including the relative potential CO_2 emissions.





SWIP-North Opportunity Evaluation

The SWIP-North opportunity evaluation tests whether Idaho Power customers would potentially benefit from Idaho Power's involvement in the project. Based on the NPV cost results detailed in Table 10.4, the SWIP-North project appears to be worth further exploration.

- Preferred Portfolio (Base with B2H) NPV—$~~7,915,702~~7,942,428
- SWIP-North Portfolio NPV—$~~7,887,562~~7,914,287

In this opportunity evaluation, the company made assumptions about SWIP-North, and its cost and capacity benefits, which are detailed more in Chapter 7. The company is not familiar with any current partnership arrangements associated with the project, whether there are opportunities to participate in the project, or the feasibility of the project in general and its associated in-service date. Given the possible benefits to Idaho Power customers, the company will engage the SWIP-North project developer and look to perform a more detailed evaluation of SWIP-North in future IRPs.

B2H Robustness Testing

The company evaluated B2H assuming five different planning margin contributions, four different costs (various contingency amounts), and two different in-service dates to consider the robustness of the B2H project.

B2H Capacity Evaluation

When the B2H project is placed into service, currently scheduled for pre-summer 2026, the company will have access to as much as 550 MW of summer capacity. In recent IRPs, the company has planned to utilize 500 MW of B2H capacity to access the Mid-C markets and purchase power.

As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity. The sensitivities with capacity amounts less than 500 MW are set up to evaluate risk related to reduced market access. The 550 MW capacity amount sensitivity quantifies potential benefits associated with leveraging additional market purchases to avoid the need for a new resource. To evaluate the impact of different B2H capacity levels, the company added or subtracted comparable capacity in the form of battery storage (the least-cost alternative to providing sufficient amounts of capacity) to maintain an adequate planning margin, while maintaining the same cost of B2H (i.e., B2H capacity's contribution toward the planning margin is reduced with no offsetting cost reduction). The resulting total portfolio costs are detailed in Table 10.8.

Table 10.8 B2H capacity sensitivities

	Portfolio NPV	Potential Offsetting Costs Not Included (NPV)
Base B2H Portfolio—350 MW Planning Contribution	$~~8,042~~8,069 million	$51 million
Base B2H Portfolio—400 MW Planning Contribution	$~~7,992~~8,019 million	$34 million
Base B2H Portfolio—450 MW Planning Contribution	$~~7,953~~7,979 million	$17 million
Base B2H Portfolio (500 MW)	$~~7,916~~7,942 million	$0
Base B2H Portfolio—550 MW Planning Contribution	$~~7,884~~7,911 million	$0
Base without B2H PAC Bridger Alignment Portfolio (for comparison)	$~~8,185~~8,208 million	N/A

Table 10.8 shows that even with a substantially reduced planning margin contribution, B2H portfolios remain cost effective. Additionally, if the company is able to access an additional 50 MW from the Mid-C market, that may present a cost-saving opportunity for customers.

The "Potential Offsetting Costs Not Included" column represents the possibility of selling wheeling service utilizing the B2H capacity that is not being utilized by the company in the given scenario. This offsetting cost is not factored into the portfolio NPV.

B2H Cost Risk Evaluation

A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Evaluating cost risks to ensure cost-effectiveness (i.e., a tipping point analysis) is an important consideration when planning for such a project. Table 10.9 details the cost of the B2H project with 0%, 10%, 20%, and 30% cost contingencies.

Table 10.9 B2H cost sensitivities

	B2H Cost Idaho Power Share TOTAL	B2H Cost 2021 IRP NPV
B2H 0% Contingency	$485 million	$159.6 million
B2H 10% Contingency	$526 million	$178.4 million
B2H 20% Contingency	$566 million	$197.2 million
B2H 30% Contingency	$607 million	$216.1 million

Utilizing the numbers in Table 10.8 and comparing them to the difference between the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio, the B2H project would have to increase significantly beyond a 30% contingency before the project would no longer be cost-effective. While this is already a significant margin, it should be noted that there are other unquantified benefits to the B2H project that if quantified, would further widen this gap. These items will be discussed in more detail in the forthcoming *Appendix D–Transmission Supplement*, which is anticipated to be filed in the first quarter of 2022.

B2H In-Service Date Risk Evaluation

The current planned in-service date for B2H is prior to the summer of 2026. This date is necessary to meet the peak demand growth needs, as well as fill in for the Valmy Unit 2 exit occurring at the end of 2025, and to facilitate the exit of Bridger Unit 3, as recommended as part of the Preferred Portfolio.

Should the B2H in-service date slip to 2027 due to a delay in receiving a permit, supply chain constraints, or other unforeseen issues, the exit of Bridger Unit 3 will certainly be delayed, and other new resources will be required in 2026. Table 10.10 details the cost change of B2H adjusting to 2027, and the new comparison to the Base without B2H PAC Bridger Alignment portfolio (the best B2H-excluded portfolio).

Table 10.10 B2H 2027 portfolio costs, cost sensitivities ($ x 1,000)

	Portfolio Costs	Portfolio Cost Compared to B2H 2027 Portfolio
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428	-$~~69,062~~69,090
Base with B2H in 2027	$~~7,984,764~~8,011,517	-
Base without B2H PAC Alignment	$~~8,185,334~~8,207,893	$~~200,570~~196,375

Slippage in the schedule from 2026 to 2027 would not be ideal for Idaho Power customers. However, B2H remains the most cost-effective long-term resource.

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

Idaho Power experiences its peak demand in late June or early July while the regional adequacy assessments suggest potential capacity deficits in late summer or winter. In the case of late summer, Idaho Power's demand has generally declined substantially; Idaho Power's irrigation customer demand begins to decrease starting in mid-July. For winter adequacy, Idaho Power generally has excess resource capacity to support the region.

The assessment of regional resource adequacy is useful in understanding the liquidity of regional wholesale electric markets. For the 2021 IRP, Idaho Power reviewed the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.

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- Base with B2H Portfolio NPV (Preferred Portfolio)—$7,942.4 million
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Under planning conditions, the Base with B2H (Preferred Portfolio) is approximately $266 million more cost effective than the best portfolio that did not include the B2H project. Detailed portfolio costs can be found in Chapter 10.

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Table 10.2 AURORA hourly simulations

	Zero Carbon	Planning Carbon	High Carbon
Planning Gas	X	X	
High Gas			X

The three combinations include the planning case scenarios as well as the bookends for natural gas and carbon adder price forecasts.

The purpose of the AURORA hourly simulations is to compare how portfolios perform throughout the 20-year timeframe of the IRP. These simulations include the costs associated with adding generation resources (both supply-side and demand-side) and optimally dispatching the resources to meet the constraints within the model. The results from the three hourly simulations, where only the pricing forecasts were changed, are shown in Table 10.3. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

Table 10.3 2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$7,942,428	$7,213,486	$9,858,726
Base B2H PAC Bridger Alignment	$8,021,906	$7,175,514	$9,955,484
Base without B2H	$8,219,281	$7,810,996	$9,501,435
Base without B2H without Gateway West[35]	$8,470,101	-	-
Base without B2H PAC Bridger Alignment	$8,207,893	$7,610,787	$9,675,450
Base with B2H—High Gas High Carbon Test[36]	$8,024,064	-	$9,451,660

[35] The company did not continue further evaluation of this portfolio beyond planning conditions due to the portfolio's inferior performance (high-cost, poor reliability, and poor emissions performance).

[36] All portfolios were optimized with planning conditions. The "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

This comparison, as well as the stochastic risk analysis applied to these portfolios (see the Stochastic Risk Analysis section of this chapter), indicate the Base with B2H portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio.

The scenarios listed in Table 10.4 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Each was evaluated under planning natural gas and carbon adder forecasts.

Table 10.4 2021 IRP Sensitivities, NPV years 2021–2040 ($ x 1,000)

Sensitivity	Cost
Preferred Portfolio (Base with B2H)	$7,942,428
SWIP-North	$7,914,287
CSPP Wind Renewal Low	$7,919,311
CSPP Wind Renewal High	$7,952,730

The validation and verification tests are listed in Table 10.5. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the Action Plan window, to ensure the model was optimizing correctly and to test assumptions. More details on the setup and expected outcome of each test are provided in Chapter 9.

Table 10.5 2021 IRP validation and verification tests, NPV years 2021–2040 ($ x 1,000)

Validation & Verification Tests	Cost
Preferred Portfolio (Base with B2H)	$7,942,428
Demand Response	$7,944,368
Energy Efficiency	$8,169,838
Natural Gas in 2028 Rather than Solar and Storage	$8,078,645
Bridger Exit Units 1 & 2 at the End of 2023	$8,077,805
Bridger Exit Unit 2 at the End of 2026	$8,014,305
Bridger Unit 2 Delayed Gas Conversion (2027)	$7,962,665
Bridger Exit Unit 4 in 2027	$7,951,878
Bridger Exit Units 3 and 4 in 2028 and 2030	$7,997,453
Geothermal	$8,000,506
Biomass	$7,994,989
Valmy Unit 2 Exit in 2023	$7,957,116
Valmy Unit 2 Exit in 2024	$7,956,390

Portfolio Emission Results

The company is seeking to execute on the actions identified in the Action Plan window. Therefore, the company evaluated the CO_2 emissions within the Action Plan window for each portfolio in contention for the Preferred Portfolio, along with the SWIP-North portfolio.

Figure 10.2 compares the full 20-year emissions of the company's 2019 Preferred Portfolio to the top contending portfolios in the 2021 IRP. In Figure 10.2, the 2019 Preferred Portfolio is on the far left, adjacent to the 2021 Preferred Portfolio on its immediate right. Compared to the 2019 Preferred Portfolio, the 2021 Preferred Portfolio has cumulative emissions reductions of about 21%. As can be seen on Figure 10.2, the other 2021 portfolios each reflect reduced emissions as compared to the 2019 Preferred Portfolio and are sorted by present value portfolio cost from left to right. The costs associated with each portfolio are shown in the yellow highlights. While 2021 IRP portfolios are shown on Figure 10.1 to have relatively similar emissions output during the Action Plan window, three portfolios have lower projected emissions than the 2021 Preferred Portfolio over the full 20-year planning horizon. However, it is important to note that each of those three portfolios present higher expected cost. The information presented on Figures 10.1 and 10.2 demonstrate that Idaho Power's CO_2 emissions can be expected to trend downward over time. Idaho Power will continue to evaluate resource needs and alternatives that balance cost and risk, including the relative potential CO_2 emissions.

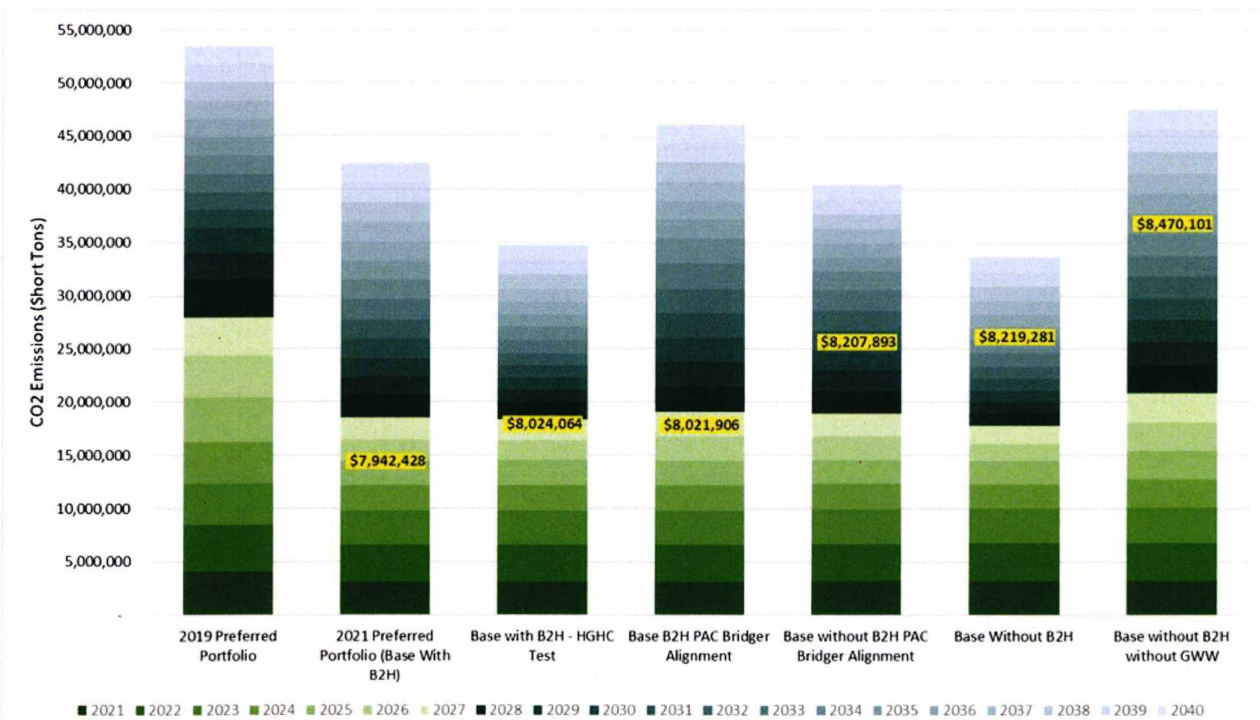

Figure 10.2 Estimated portfolio emissions from 2021–2040

In conclusion, the Preferred Portfolio (Base with B2H) strikes an appropriate balance of cost, risk, and emissions reductions over the Action Plan window. The Preferred Portfolio also lays a cost-effective foundation to build upon for further emissions reductions into the future.

SWIP-North Opportunity Evaluation

The SWIP-North opportunity evaluation tests whether Idaho Power customers would potentially benefit from Idaho Power's involvement in the project. Based on the NPV cost results detailed in Table 10.4, the SWIP-North project appears to be worth further exploration.

- Preferred Portfolio (Base with B2H) NPV—$7,942,428
- SWIP-North Portfolio NPV—$7,914,287

In this opportunity evaluation, the company made assumptions about SWIP-North, and its cost and capacity benefits, which are detailed more in Chapter 7. The company is not familiar with any current partnership arrangements associated with the project, whether there are opportunities to participate in the project, or the feasibility of the project in general and its associated in-service date. Given the possible benefits to Idaho Power customers, the company will engage the SWIP-North project developer and look to perform a more detailed evaluation of SWIP-North in future IRPs.

B2H Robustness Testing

The company evaluated B2H assuming five different planning margin contributions, four different costs (various contingency amounts), and two different in-service dates to consider the robustness of the B2H project.

B2H Capacity Evaluation

When the B2H project is placed into service, currently scheduled for pre-summer 2026, the company will have access to as much as 550 MW of summer capacity. In recent IRPs, the company has planned to utilize 500 MW of B2H capacity to access the Mid-C markets and purchase power.

As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity. The sensitivities with capacity amounts less than 500 MW are set up to evaluate risk related to reduced market access. The 550 MW capacity amount sensitivity quantifies potential benefits associated with leveraging additional market purchases to avoid the need for a new resource. To evaluate the impact of different B2H capacity levels, the company added or subtracted comparable capacity in the form of battery storage (the least-cost alternative to providing sufficient amounts of capacity) to maintain an adequate planning margin, while maintaining the same cost of B2H (i.e., B2H capacity's contribution toward the planning margin is reduced with no offsetting cost reduction). The resulting total portfolio costs are detailed in Table 10.8.

Table 10.8 B2H capacity sensitivities

	Portfolio NPV	Potential Offsetting Costs Not Included (NPV)
Base B2H Portfolio—350 MW Planning Contribution	$8,069 million	$51 million
Base B2H Portfolio—400 MW Planning Contribution	$8,019 million	$34 million
Base B2H Portfolio—450 MW Planning Contribution	$7,979 million	$17 million
Base B2H Portfolio (500 MW)	$7,942 million	$0
Base B2H Portfolio—550 MW Planning Contribution	$7,911 million	$0
Base without B2H PAC Bridger Alignment Portfolio (for comparison)	$8,208 million	N/A

Table 10.8 shows that even with a substantially reduced planning margin contribution, B2H portfolios remain cost effective. Additionally, if the company is able to access an additional 50 MW from the Mid-C market, that may present a cost-saving opportunity for customers.

The "Potential Offsetting Costs Not Included" column represents the possibility of selling wheeling service utilizing the B2H capacity that is not being utilized by the company in the given scenario. This offsetting cost is not factored into the portfolio NPV.

B2H Cost Risk Evaluation

A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Evaluating cost risks to ensure cost-effectiveness (i.e., a tipping point analysis) is an important consideration when planning for such a project. Table 10.9 details the cost of the B2H project with 0%, 10%, 20%, and 30% cost contingencies.

Table 10.9 B2H cost sensitivities

	B2H Cost Idaho Power Share TOTAL	B2H Cost 2021 IRP NPV
B2H 0% Contingency	$485 million	$159.6 million
B2H 10% Contingency	$526 million	$178.4 million
B2H 20% Contingency	$566 million	$197.2 million
B2H 30% Contingency	$607 million	$216.1 million

Utilizing the numbers in Table 10.8 and comparing them to the difference between the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio, the B2H project would have to increase significantly beyond a 30% contingency before the project would no longer be cost-effective. While this is already a significant margin, it should be noted that there are other unquantified benefits to the B2H project that if quantified, would further widen this gap. These items will be discussed in more detail in the forthcoming

Appendix D–Transmission Supplement, which is anticipated to be filed in the first quarter of 2022.

B2H In-Service Date Risk Evaluation

The current planned in-service date for B2H is prior to the summer of 2026. This date is necessary to meet the peak demand growth needs, as well as fill in for the Valmy Unit 2 exit occurring at the end of 2025, and to facilitate the exit of Bridger Unit 3, as recommended as part of the Preferred Portfolio.

Should the B2H in-service date slip to 2027 due to a delay in receiving a permit, supply chain constraints, or other unforeseen issues, the exit of Bridger Unit 3 will certainly be delayed, and other new resources will be required in 2026. Table 10.10 details the cost change of B2H adjusting to 2027, and the new comparison to the Base without B2H PAC Bridger Alignment portfolio (the best B2H-excluded portfolio).

Table 10.10 B2H 2027 portfolio costs, cost sensitivities ($ x 1,000)

	Portfolio Costs	Portfolio Cost Compared to B2H 2027 Portfolio
Preferred Portfolio (Base with B2H)	$7,942,428	-$69,090
Base with B2H in 2027	$8,011,517	-
Base without B2H PAC Alignment	$8,207,893	$196,375

Slippage in the schedule from 2026 to 2027 would not be ideal for Idaho Power customers. However, B2H remains the most cost-effective long-term resource.

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

Idaho Power experiences its peak demand in late June or early July while the regional adequacy assessments suggest potential capacity deficits in late summer or winter. In the case of late summer, Idaho Power's demand has generally declined substantially; Idaho Power's irrigation customer demand begins to decrease starting in mid-July. For winter adequacy, Idaho Power generally has excess resource capacity to support the region.

The assessment of regional resource adequacy is useful in understanding the liquidity of regional wholesale electric markets. For the 2021 IRP, Idaho Power reviewed the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.