BUILDING OUR FUTURE

September 2023

IRP

INTEGRATED RESOURCE PLAN

IDAHO POWER®

SAFE HARBOR STATEMENT

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GLOSSARY OF ACRONYMS

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

akW—Average Kilowatt

aMW—Average Megawatt

ASHP—Air-Source Heat Pump

ATC—Available Transfer Capacity

B2H—Boardman to Hemingway

BAA—Balancing Authority Area

BESS—Battery Energy Storage System

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CAISO—California Independent System Operator

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

CEYW—Clean Energy Your Way

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CO2—Carbon Dioxide

CPCN—Certificate of Public Convenience and Necessity

CPP—Critical Peak Pricing

CSPP—Cogeneration and Small-Power Production

CWA—Clean Water Act of 1972

DOE—Department of Energy

DPO—Draft Proposed Order

DR—Demand Response

DSM—Demand-Side Management

DSP—Distribution System Planning

EE—Energy Efficiency

EFSC—Energy Facility Siting Council

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

ELCC—Effective Load Carrying Capability

ELR—Energy Limited Resource

EPA—Environmental Protection Agency

ESA—Energy Service Agreement
ESPA—Eastern Snake River Plain Aquifer
ESPAM—Eastern Snake Plain Aquifer Model
FCRPS—Federal Columbia River Power System
FERC—Federal Energy Regulatory Commission
FPA—Federal Power Act of 1920
FPI—Fire Potential Index
GHG—Greenhouse Gas
GSHP—Ground-Source Heat Pump
GWMA—Ground Water Management Area
GWW—Gateway West
H2—Hydrogen
HB—House Bill
HCC—Hells Canyon Complex
INL—Idaho National Laboratory
IPCC—Intergovernmental Panel on Climate Change
IPUC—Idaho Public Utilities Commission
IRA—Inflation Reduction Act of 2022
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
ISEA—Idaho Strategic Energy Alliance
ISO—International Standards Organization
ITC—Investment Tax Credit
IWRB—Idaho Water Resource Board
kV—Kilovolt
kW—Kilowatt
kWh—Kilowatt-Hour
LCOC—Levelized Cost of Capacity
LCOE—Levelized Cost of Energy
Li-ion—Lithium Ion
LiDAR—Light Detection and Ranging
LOLE—Loss of Load Expectation
LTCE—Long-Term Capacity Expansion
MMBtu—Million British Thermal Units
MSA—Metropolitan Statistical Area
MW—Megawatt
MWh—Megawatt-Hour
NEPA—National Environmental Policy Act of 1969

NOx—Nitrogen Oxide

NPV—Net Present Value

O&M—Operations and Maintenance

ODOE—Oregon Department of Energy

OPUC—Public Utility Commission of Oregon

PCA—Power Cost Adjustment

PPA—Power Purchase Agreement

PRM—Planning Reserve Margin

PTC—Production Tax Credit

PURPA—Public Utility Regulatory Policies Act of 1978

PV—Photovoltaic

QF—Qualifying Facility

RCAT—Reliability and Capacity Assessment Tool

REC—Renewable Energy Certificate

RFA—Request for Amendment

RFP—Request for Proposal

ROD—Record of Decision

ROR—Run-of-River

RPS—Renewable Portfolio Standard

SCCT—Simple-Cycle Combustion Turbine

SCR—Selective Catalytic Reduction

SIP—State Implementation Plan

SMR—Small Modular Reactor

SNOWIE—Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment

SRBA—Snake River Basin Adjudication

SWIP-N—Southwest Intertie Project-North

T&D—Transmission and Distribution

TOU—Time-of-Use

TRC—Total Resource Cost

TRM—Transmission Reliability Margin

UCT—Utility Cost Test

VER—Variable Energy Resource

WECC—Western Electricity Coordinating Council

WMP—Wildfire Mitigation Plan

WPP—Western Power Pool

WRAP—Western Resource Adequacy Program

EXECUTIVE SUMMARY

Introduction

The 2023 Integrated Resource Plan (IRP) is Idaho Power's 16th resource plan prepared in accordance with regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2023 IRP evaluates the 20-year planning period from 2024 through 2043. During this period, Idaho Power's demand for electricity is expected to grow significantly. Over the 20-year forecast period, the company's peak load is expected to grow by approximately 80 megawatts (MW) per year, or 1,500 MW over the next two decades. Continued customer growth is driving demand, and the average annual number of customers is expected to increase from nearly 639,000 in 2024 to 855,000 by 2043.

To meet this growing demand, the 20-year IRP includes the addition of large quantities of cost-effective clean resources: 3,325 MW of solar, 1,800 MW of wind, 1,453 MW of battery storage, 360 MW of energy efficiency, 340 MW of peaking hydrogen, 160 MW of incremental demand response, and 30 MW of geothermal. The 2023 IRP also identifies the conversion of coal-fired generation units to natural gas, including Valmy units 1 and 2 and Bridger units 3 and 4. These conversions are cost-effective, ensure future reliability, and result in significant reductions in the company's forecasted carbon dioxide (CO_2) emissions. With these conversions, the company's operations will be free from coal-fired generation beginning in 2030.

Energy experts, engineers, and system operators generally agree that new, high-voltage transmission systems are necessary for a reliable energy future. "New and upgraded transmission lines deliver electricity to where it's needed, whether that means delivering wind and solar power to towns and cities across the country or moving power from one region to another that needs it in the face of storms, heat waves, or extreme weather."[1] Consistent with this recent statement and Idaho Power's own IRP analysis dating back to 2009, the 2023 IRP includes transmission as a cost-effective way to integrate renewables and facilitate regional energy exchange. Specifically, the IRP includes the Boardman to Hemingway (B2H) 500-kilovolt (kV) transmission line in 2026 to connect the Pacific Northwest and Idaho; and three Gateway West (GWW) transmission phases spread across the 20-year plan to connect the Magic Valley and Treasure Valley, with the first phase (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation) modeled with an online date of late 2028. The company has also identified potential value associated with the addition of the Southwest

[1] whitehouse.gov/briefing-room/statements-releases/2022/11/18/fact-sheet-the-biden-harris-administration-advances-transmission-buildout-to-deliver-affordable-clean-electricity/.

Intertie Project-North (SWIP-N) transmission line. The 500-kV SWIP-N line would run between Idaho and Nevada, with connectivity to the Las Vegas area. Idaho Power's potential involvement in the project remains uncertain and, therefore, the SWIP-N project is not included in the Preferred Portfolio of this IRP.

The IRP is a 20-year plan, prepared biennially, which has historically allowed Idaho Power to timely update its long-term resource plan based on changing circumstances. However, balancing load and resources has become increasingly more dynamic as major planning inputs and assumptions are subject to change in real-time. These long-term planning challenges are not unique to Idaho Power; however, several individual uncertainties in this planning cycle are specific to Idaho Power. Due to the increased level of uncertainty surrounding several important near-term decisions, the 2023 IRP has been prepared in a manner intended to provide the flexibility and adaptability necessary to inform decisions as more information becomes known before the next planning cycle. A few examples include load growth, the timing of the B2H transmission line in-service date, and Idaho Power's potential involvement in the SWIP-N project. These, and other planning scenarios, are discussed in greater detail throughout this planning document.

IRP Methodology Improvements

The primary goal of the long-term resource planning process is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs. In each IRP, the company models resource needs over a 20-year planning period with the primary objective of minimizing costs and risks to customers.

As in prior planning cycles, Idaho Power used Energy Exemplar's AURORA model for the 2023 IRP. Using AURORA's Long-Term Capacity Expansion (LTCE) modeling tool, resources are selected from a variety of supply- and demand-side resource options to develop portfolios that are least-cost for a variety of alternative future scenarios while meeting reliability criteria. The model can also select an exit from or a conversion to natural gas for existing coal generation units, as well as build resources based on economics absent a defined capacity need. The LTCE modeling process is discussed in further detail in Chapter 9—Portfolios.

To ensure that AURORA develops least-cost, reasonable, and defensible portfolios, Idaho Power performed validation and verification tests to confirm the model is operating as expected and producing the most economic portfolio under numerous variations of resources and timing.

To verify that AURORA-built resource portfolios meet Idaho Power's reliability requirements, the company leveraged the Loss of Load Expectation (LOLE) methodology and calculated annual capacity positions to meet a LOLE threshold of 0.1 event-days per year.

Details about the validation and verification process can be found in Chapter 9—Portfolios, and a discussion of the results can be found in Chapter 10—Modeling Analysis. An in-depth discussion of the LOLE calculation process can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

For each portfolio, Idaho Power modeled costs and benefits including:

- Construction costs
- Fuel costs
- Operations and Maintenance (O&M) costs
- Transmission upgrade costs associated with interconnecting new resource options
- Natural gas pipeline reservation and new natural gas pipeline infrastructure costs
- Projected wholesale market purchases and sales
- Anticipated environmental controls
- Market value of Renewable Energy Certificates (REC) for REC-eligible resources
- Investment/Production Tax Credits (ITC/PTC) associated with qualifying generation

Additionally, to enhance the risk evaluation within the 2023 IRP, the company worked with the IRP Advisory Council (IRPAC) to develop a variety of scenarios that build portfolios based on several hypothetical versions of the future. Some of the hypothetical futures align with Idaho Power's near- and long-term objectives, making the associated scenario portfolios a good point of comparison to the final Preferred Portfolio. Specifically, the company used the scenario results to confirm that decisions identified in the Near-Term Action Plan window (2024–2028) are robust and reliable across different futures. The future scenarios developed with IRPAC include:

- High Prices: High natural gas price and high price on carbon emissions
- Low Prices: Low natural gas price and zero price on carbon emissions
- Constrained Storage: Increased battery storage prices that would result from an assumed lithium shortage
- 100% Clean by 2035: All electricity resources must be clean (non-carbon emitting) by 2035
- 100% Clean by 2045: All electricity resources must be clean (non-carbon emitting) by 2045
- Additional Large Load: High customer growth scenario

- New Forecasted PURPA[2] Resources: Assumes additional must-take generating resources at set prices consistent with state and federal policy
- Extreme Weather: Assumes more frequent extreme weather that increases demand for electricity
- Rapid Electrification: Assumes rapid and substantial movement of individuals and industries to more electrified products and resources, increasing demand for electricity
- Load Flattening: Assumes a shift of demand for electricity from Idaho Power's peak hours to lower-demand hours during the day, thereby "flattening" the visual shape of the demand for electricity across the day

Portfolio Analysis Overview

The AURORA model selects resources based on set criteria—primarily, resources that most cost-effectively meet future demand for electricity *and* maintain Idaho Power's reliability criteria. Generally, resources in the model are "selectable," meaning the model can pick a given resource—such as adding solar or batteries—if doing so will help achieve the model's objectives of building the lowest-cost, most-reliable portfolio.[3] Conversely, the model can choose *not* to select resources if doing so will lead to higher costs or an unreliable portfolio that doesn't meet demand requirements.

Ultimately, the best portfolio—the one that meets all demand and reliability criteria—at the best combination of least cost and least risk is selected as the Preferred Portfolio. Put simply, the Preferred Portfolio is the best and most affordable path to meet the needs of Idaho Power's customers for the next 20 years, based on information known today. The Preferred Portfolio reflects *additional* resources to Idaho Power's system and, apart from identifying an exit from certain resources, does not present the company's current system and existing resource mix.

For the 2023 IRP, Idaho Power identified several key resources or potential projects to evaluate in additional detail, and the company required the model to build portfolios both with and without each resource or project. These with and without views help Idaho Power and interested parties understand the impacts of major decision points. These with and without views include:

- With and without the B2H project

[2] *Public Utility Regulatory Policies Act of 1978* (PURPA)

[3] In some instances, resources are not selectable and are treated as "must take" or have conditions placed upon them. These specific conditions are discussed in Chapter 5—Future Supply-Side Generation and Storage Resources and *Appendix C—Technical Report.*

- With and without different phases of the Gateway West project
- With and without specific Valmy Unit 1 and Unit 2 natural gas conversion date assumptions

These portfolios were compared against each other to determine which portfolios could be eliminated from contention, and where to focus additional portfolio robustness testing.

To validate the resource selection and robustness of the Preferred Portfolio, the company performed additional scenario and sensitivity analyses, including the following:

- The resources selected in the Near-Term Action Plan window of the Preferred Portfolio were compared to optimal resources selected for alternative future scenarios, identified in conjunction with IRPAC, to determine the changes that would need to be made in each of those scenarios.
- Validation and verification studies were performed to test coal exit dates, Bridger and Valmy unit natural gas conversions, and both supply-side and demand-side resources.

2023 Preferred Portfolio

Idaho Power's selected Preferred Portfolio for the 2023 IRP includes a diverse mix of generation resources, storage, and transmission. Specifically, the Preferred Portfolio adds 3,325 MW of solar, 1,800 MW of wind, 1,453 MW of storage (four- and eight-hour batteries, as well as long-duration 100-hour storage), 360 MW of additional energy efficiency (EE), 340 MW of hydrogen (H2), 160 MW of new demand response (DR), and 30 MW of geothermal. Additionally, the Preferred Portfolio includes conversions of multiple coal-fired generation units to natural gas, showing the company exiting coal entirely in 2030 and adding a net total of 261 MW of natural gas via coal conversions through 2043. In total, the Preferred Portfolio—considering both additions and exits—adds 6,888 MW of resource capacity over the next 20 years. To support these resource additions, the Preferred Portfolio also includes the B2H transmission line beginning in July 2026 and three Gateway West transmission line segments phased in from 2029 to 2040.

Table 1.1 shows the resource additions, coal exits, as well as new transmission that make up Idaho Power's 2023 IRP Preferred Portfolio. Within AURORA, Idaho Power names each portfolio with a short reference that describes a notable aspect of the portfolio. As shown in Table 1.1, the short-hand name of the Preferred Portfolio is "Valmy 1 & 2", referring to the portfolio's conversion of both Valmy units from coal to natural gas.

Table 1.1 Preferred Portfolio additions and coal exits (MW)

Preferred Portfolio—Valmy 1 & 2 (MW)												
Year	Coal Exits	Gas	H2	Wind	Solar	4 Hr	8 Hr	100 Hr	Trans.	Geo	DR	EE Forecast
2024	-357	357	0	0	100	96	0	0	0	0	0	17
2025	0	0	0	0	200	227	0	0	0	0	0	18
2026	-134	261	0	0	100	0	0	0	Jul B2H	0	0	19
2027	0	0	0	400	375	5	0	0	0	0	0	20
2028	0	0	0	400	150	5	0	0	0	0	0	21
2029	0	0	0	400	0	5	0	0	GWW1	0	20	22
2030	-350	350	0	100	500	155	0	0	0	30	0	21
2031	0	0	0	400	400	5	0	0	GWW2	0	0	21
2032	0	0	0	100	100	205	0	0	0	0	0	20
2033	0	0	0	0	0	105	0	0	0	0	20	20
2034	0	0	0	0	0	5	0	0	0	0	40	19
2035	0	0	0	0	0	5	0	0	0	0	40	18
2036	0	0	0	0	0	5	0	0	0	0	40	17
2037	0	0	0	0	0	55	50	0	0	0	0	17
2038	0	-706	340	0	0	155	50	200	0	0	0	17
2039	0	0	0	0	0	5	50	0	0	0	0	15
2040	0	0	0	0	400	5	0	0	GWW3	0	0	14
2041	0	0	0	0	200	5	0	0	0	0	0	14
2042	0	0	0	0	200	55	0	0	0	0	0	14
2043	0	0	0	0	600	0	0	0	0	0	0	14
Sub Total	**841**	**261**	**340**	**1,800**	**3,325**	**1,103**	**150**	**200**		**30**	**160**	**360**
Total	**6,888**											

Preferred Portfolio Changes from the 2021 IRP

The Preferred Portfolio of the 2023 IRP reflects movement toward clean, low-cost resources, while maintaining focus on system reliability. Table 1.2 highlights the changes from the 2021 IRP to the 2023 IRP.

Table 1.2 2023 IRP comparison to the 2021 IRP

2021 IRP Preferred Portfolio	2023 IRP Preferred Portfolio
The last coal generation unit exit was planned in 2028.	Coal generation units have planned conversions to natural gas with the last taking place by 2030.
Emissions gradually reduced to approximately 1.8M short tons of CO_2 by the end of the plan.	CO_2 emissions fall to just over 500-k short tons by the end of the plan—less than half the emissions as the previous IRP.
The B2H transmission line was identified as a least-cost resource.	B2H continues to be a least-cost resource.
The plan included a conversion of Bridger coal units 1 and 2 to natural gas operation.	Bridger units 1, 2, 3, and 4 as well as Valmy units 1 and 2 are identified for a natural gas conversion.
700 MW of wind plus 1,405 MW of solar were included.	1,800 MW of wind plus 3,325 MW of solar are included.
1,685 MW of battery storage was included.	1,453 MW of storage was included, including 200 MW of long-duration storage.
An additional 100 MW of DR was selected.	An additional 160 MW of DR is selected.
A total of 440 MW of cost-effective EE was selected.	A total of 360 MW of EE is selected.
GWW was not included.	GWW is identified as necessary for system reliability and to enable incremental renewables.
No new firm capacity generation resources were identified.	Two hydrogen peaking units are selected in 2038 to replace the Bridger natural gas converted units.

Importantly, the 2021 and 2023 IRPs were assessed on the same principles of minimizing cost and risk (i.e., the least-cost, least-risk portfolio). Relative to the 2021 IRP, the 2023 IRP Preferred Portfolio includes significantly more wind and solar resources to meet increased load projections, driving the need for Gateway West transmission phases to facilitate the interconnection and delivery of 1,800 MW of wind and 3,325 MW of solar.

To maintain reliability for all seasons of each year across the modeled time horizon, the company will convert four coal units to natural gas. Valmy units 1 and 2 are identified for a conversion in 2026, and Bridger units 3 and 4 in 2030. Idaho Power plans to be out of all coal operations in 2030. With respect to natural gas, the only additions in the 2023 IRP stem from coal-to-natural gas conversions.

The quantity of DR has grown considerably in the 2023 IRP, with 160 MW of incremental DR included in the Preferred Portfolio compared to 100 MW in the 2021 IRP. Finally, cost-effective EE measures continue to be a major part of the plan in the 2023 IRP, with a total of 360 MW of incremental EE across the 20-year planning horizon.

Near-Term Action Plan (2024–2028)

The Near-Term Action Plan for the 2023 IRP reflects actionable items in the Preferred Portfolio from 2024 to 2028. The Near-Term Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally conscious service to customers into the future. The current regional electric market, regulatory environment, and the pace of technological change make the 2023 Near-Term Action Plan especially relevant.

To reduce confusion around near-term actions in the 2023 IRP, Idaho Power has developed two separate groups of actions. The first group includes actions that Idaho Power will take in the future, but to which the company was already committed prior to review of the 2023 IRP. The company is not requesting regulatory acknowledgment of the items in this group. In contrast, the second group includes actions to which the company has not yet committed or is not fully committed and for which the company is seeking regulatory acknowledgment in this 2023 IRP.

Actions Committed to Prior to the 2023 IRP—Not for Regulatory Acknowledgment

- 100 MW of solar and 96 MW of four-hour storage added in 2024 (resources selected through Requests for Proposals [RFP])
- Conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024 (conversions scheduled to occur by summer of 2024)
- 95 MW of additional cost-effective EE between 2024 and 2028 (added EE identified in Idaho Power's *2022 Energy Efficiency Potential Study*)
- 200 MW of solar added in 2025 (executed contract for clean energy customer resource)
- 227 MW of four-hour storage added in 2025 (resources selected from the 2024 RFP)

2023 IRP Decisions for Acknowledgment

- B2H online by summer 2026
- Continue exploring Idaho Power's potential participation in the SWIP-N project
- Install cost-effective distribution-connected storage from 2025 through 2028
- Convert Valmy units 1 and 2 from coal to natural gas by summer 2026
- If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources, in 2026 through 2028 (inclusive of 625 MW of forecast Clean Energy Your Way [CEYW] resources)
- Explore a 5 MW long-duration storage pilot project
- Include 14 MW of capacity associated with the Western Resource Adequacy Program (WRAP)
- Midpoint–Hemingway #2 500-kV, Midpoint–Cedar Hill 500-kV, and Mayfield 500-kV substation (Gateway West Phase 1) online by end-of-year 2028

Further discussion of resource actions in the Near-Term Action Plan window, and attributes of the Preferred Portfolio, is included in Chapter 11—Preferred Portfolio and Action Plan. Table 1.3 includes a chronological listing of the near-term actions.

Table 1.3 Near-Term Action Plan (2024–2028)

Year	Action
2023–2024	Continue exploring potential participation in the SWIP-N project
2024	Add 100 MW of solar and 96 MW of four-hour storage
Summer 2024	Convert Bridger units 1 and 2 from coal to natural gas
2024–2028	Add 95 MW of cost-effective EE between 2024 and 2028
2024–2028	Explore a 5 MW long-duration storage pilot project
2025	Add 200 MW of solar
2025	Add 227 MW of four-hour storage
2025–2028	Install cost effective distribution-connected storage
Summer 2026	Bring B2H online
Summer 2026	Convert Valmy units 1 and 2 from coal to natural gas
2026–2028	If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources
2027	Include 14 MW of capacity associated with WRAP
2028	Bring the first phase of GWW online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation)

Given the complexities and ongoing developments related to Valmy and Bridger units, B2H, and Gateway West, an update on each is provided below. Additionally, a status update on the SWIP-N project is also provided below.

Valmy Unit Conversions and Exits

As co-owners of the North Valmy Generating Station, NV Energy and Idaho Power aligned on 2026 as the year to evaluate the coal to gas conversion for units 1 and 2. Idaho Power owns half of the North Valmy Generating Station. Although Idaho Power exited coal operations at Unit 1 in 2019, if Unit 1 is converted to natural gas-operation, the company would have the option to participate in the conversion. NV Energy owns the remaining half of both units and is the plant operator.

For the 2023 IRP, Idaho Power used AURORA's LTCE model to determine the best Valmy operating option specific to Idaho Power's system subject to the following constraints:

- Allow for the exit of Unit 2 at the end of 2025 or the conversion to natural gas with SCR in 2026.

- If the conversion of Unit 2 to natural gas is selected, then the conversion of Unit 1 with SCR becomes available to the model and it can either select to remain out of Unit 1 or to convert it to natural gas operation.

In the event that the model selects any conversion to natural gas option, the company also evaluated early retirement dates of the converted natural gas units. The results of the LTCE model indicate that the conversion of Valmy units 1 and 2 to natural gas in 2026 is economical and the units will continue to economically run through the 20-year plan. To ensure the robustness of these modeling outcomes, the company performed validation and verification studies around the Unit 1 and Unit 2 conversion or exit determination. These validation and verification studies are detailed in Chapter 9—Portfolios.

Bridger Unit Conversions and Exits

Idaho Power owns one-third of Bridger units 1–4, and PacifiCorp owns the remaining two-thirds and is the plant operator. In its 2023 IRP, PacifiCorp concluded it would be cost-effective to convert Bridger units 3 and 4 to natural gas beginning in 2030 and operate as a natural gas plant through 2037. Idaho Power and PacifiCorp have not developed contractual terms that would be necessary to allow for the potential earlier exit or conversion to a non-coal fuel source by one party or both parties for units 3 and 4. Any new contractual terms may impact costs and assumptions and, therefore, affect the specific timing of exits identified in the 2023 IRP.

For the 2023 IRP, Idaho Power used AURORA's LTCE model to determine the best Bridger operating option specific to Idaho Power's system subject to the following constraints:

- Units 1 and 2—Convert to natural gas in 2024 and operate through 2037.
- Unit 3—Can exit no earlier than year-end 2025 and must either exit from coal at year-end 2029 or convert to natural gas by summer 2030. If the unit converts to natural gas, it operates through 2037.
- Unit 4—Can exit no earlier than year-end 2025 and must either exit from coal at year-end 2029 or convert to natural gas by summer 2030. If the unit converts to natural gas, it operates through 2037.

The model results indicate that the conversion of units 3 and 4 to natural gas in 2030, with operation through 2037, is economical. To ensure the robustness of these modeling outcomes, the company performed validation and verification studies around the unit 3 and 4 conversion or exit determination. These validation and verification studies are detailed in Chapter 9—Portfolios. The company will continue to evaluate whether to exit or convert Bridger units 3 and 4 to natural gas in the 2025 IRP.

Boardman to Hemingway

Idaho Power plans to break ground on the B2H project in the fourth quarter of 2023. Since the 2021 IRP, Idaho Power has accomplished the following actions:

- Received Certificates of Public Convenience and Necessity (CPCN) from the OPUC and IPUC.
- Received a site certificate for the project from the Oregon Energy Facility Siting Council (EFSC), which was affirmed on appeal to the Oregon Supreme Court.
- Completed a purchase and sale transfer agreement with Bonneville Power Administration (BPA) increasing Idaho Power's share of the project to 45.45%.
- Executed a construction agreement with PacifiCorp.
- Executed a joint purchase and sale agreement with PacifiCorp exchanging various assets, including Idaho Power gaining ownership of assets that provide access to the Four Corners market hub.

Although Idaho Power has right of way grants from the Bureau of Land Management (BLM) and the site certificate from Oregon Department of Energy (ODOE), both entities require additional steps prior to authorizing construction. Idaho Power is working through the BLM's process to secure Notice To Proceed approvals and with the ODOE to obtain Pre-Construction Compliance Determinations. Idaho Power expects these authorizations to be granted in phases between the fourth quarter of 2023 and third quarter of 2024. Additionally, Idaho Power is in the process of securing bids and awarding contracts for the various aspects of the project to move into the construction phase.

In the 2023 IRP, the company evaluated a resource portfolio without B2H to determine whether B2H remains cost-effective. This sensitivity revealed that B2H is even more cost-effective than it was shown to be in the in the 2021 IRP.

- Preferred Portfolio (with B2H) Net Present Value (NPV)—$9,746 million
- Portfolio without B2H Portfolio NPV—$10,582 million
- B2H NPV Cost Effectiveness Differential—$836 million

Under planning conditions, the inclusion of B2H (Preferred Portfolio) is approximately $836 million more cost effective than the portfolio run under the same conditions without the B2H project (up from approximately a $266 million difference in the 2021 IRP). Detailed portfolio costs can be found in Chapter 10—Modeling Analysis.

The cost-effectiveness of B2H has continued to increase even with increased pressures on project costs. The company has included its most recent B2H estimate, updated in

September 2023, inclusive of a contingency amount. There are four primary reasons for the increased benefits associated with B2H:

1. Competing IRP resources have also experienced cost increase pressures.
2. In the 2021 IRP, the company modeled the termination of 510 MW of transmission-service-related revenue upon the completion of B2H. In the 2023 IRP, following discussions with the transmission customer, Idaho Power is no longer assuming termination of this service. This change resulted in the addition of wheeling revenue related to this service and the adjustment of Midpoint West available transmission capacity for determining the GWW transmission trigger levels from resource additions.
3. The company's summer load growth has accelerated in the years directly following B2H in-service, further increasing the cost effectiveness of the project.
4. The company's winter needs, which were not a major consideration in the 2021 IRP, have accelerated due to industrial load growth. The company's B2H-related asset exchange with PacifiCorp enables 200 MW of additional winter connectivity.

Gateway West Phase 1

In the 2023 IRP, the company has identified the need for multiple Gateway West phases within the 20-year planning window. The first Idaho Power Gateway West phase, which falls within the Action Plan window, is the Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield 500-kV substation (GWW Phase 1), which will collectively relieve Idaho Power's constrained transmission system between the Magic Valley and the Treasure Valley. There were no Gateway West phases identified for inclusion in the Preferred Portfolio of the 2021 IRP, but that has changed in the 2023 IRP primarily because of the following considerations: 1) a significant increase in the company's near-term load forecast and 2) continuation of tax credits associated with wind and solar resources. With respect to the first consideration, Idaho Power's larger near-term load forecast results in the need for more generation resources. As a result, AURORA is selecting large amounts of cost-effective renewable resources—and Gateway West will be distinctly suited to bring that electricity to load centers. Similarly, the continuation of tax credits makes renewables more cost-effective in the model, thereby adding more renewables and making Gateway West even more necessary to enable delivery of the additional renewables.

To evaluate the cost effectiveness of transmission facilities, the company uses AURORA's LTCE model. A transmission facility is evaluated by first developing an optimal portfolio inclusive of the transmission facility, and second an optimal portfolio exclusive of the transmission facility.

The Preferred Portfolio, inclusive of GWW Phase 1, is $577 million NPV more cost effective than the optimized portfolio that is exclusive of any Gateway West phases.

- Preferred Portfolio (with GWW) NPV—$9,746 million
- Portfolio without GWW NPV—$10,326 million
- GWW NPV Cost Effectiveness Differential—$580 million

Transmission is a necessity to interconnect and deliver electricity from new resources. Some resources, such as natural gas power plants, can theoretically be sited near load without major transmission upgrades, but even this can be challenging due to factors, such as natural gas pipeline limitations and air quality permitting. The “Without Gateway West Phases” portfolio illustrates that even if local area challenges can be overcome, a future *without* Gateway West is not cost effective.

The company’s additional load growth, coupled with opportunities to leverage wind and solar tax credits, necessitate additional east-to-west transmission connectivity across southern Idaho to enable a least-cost, least-risk resource portfolio.

Southwest Intertie Project-North

SWIP-N is a federally permitted 500-kV transmission project being developed by Great Basin Transmission, LLC, which would provide a connection between southern Idaho and southern Nevada. As part of the 2023 IRP process, the company has identified potential value associated with the addition of SWIP-N.

SWIP-N is a unique opportunity that could provide Idaho Power a transmission connection to the southern power markets that could be leveraged in the winter months and further diversify the company’s market access. Idaho Power’s interest in the SWIP-N project would be in the south-to-north direction. Based on the California Independent System Operator (CAISO) plan[4], CAISO may have an interest in the north-to-south capacity on the project. Due to Idaho Power’s interest in only a minority capacity position and uncertainty that is inherent around potential co-participant arrangements on the project, Idaho Power has not placed SWIP-N into its Preferred Portfolio of resources for the 2023 IRP.

Should the company decide to move forward with the project, the company will seek appropriate regulatory review and approval. Depending on the timing of Idaho Power’s decision, the company may supplement the 2023 IRP proceedings in the Idaho and Oregon jurisdictions with additional SWIP-N related information.

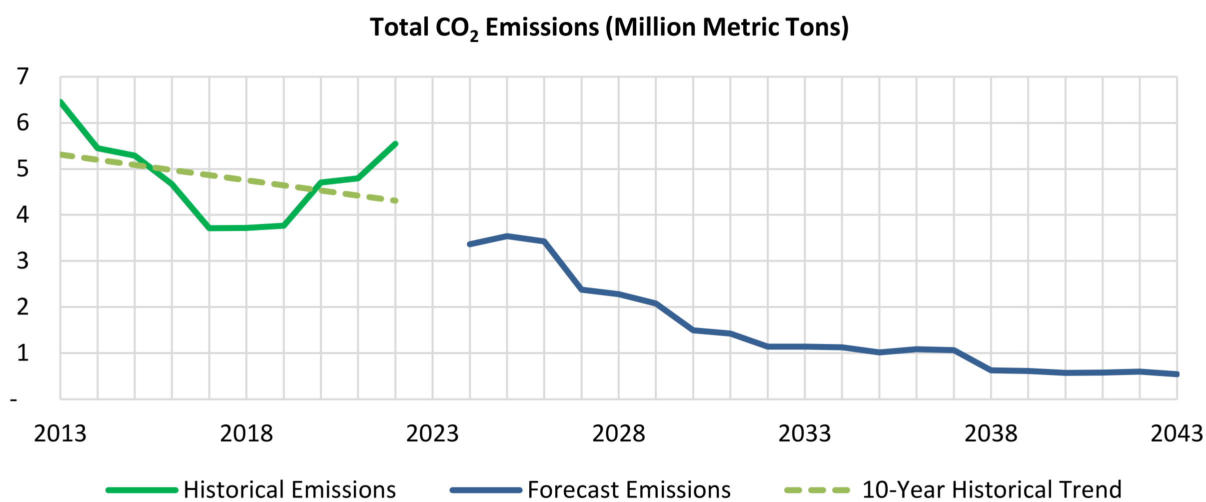
[4] ISO-Board-Approved-2022-2023-Transmission-Plan.pdf (caiso.com).

Historical and Forecasted Emissions

Since the 2021 IRP, Idaho Power has taken significant steps toward reducing carbon emissions. The emissions impact of these steps is discussed in Chapter 3—Clean Energy & Climate Change and include the conversion of all four Bridger units and both Valmy units from coal to natural gas operations, as well as the addition of significant amounts of clean resources, such as solar, wind, and storage.

Because Idaho Power uses clean hydropower resources, the company's carbon emissions vary annually based on factors that influence hydropower production, including precipitation and temperature. Low hydro conditions, which materialized in both 2021 and 2022, result in the need for Idaho Power to leverage resources that produce carbon emissions. As seen in Table 1.4, historical emissions (generation emissions plus emissions from purchased power minus emissions from sold power) were higher in low hydro years. Despite individual year increases, the historical trend is downward. Emissions for 2023 were not available at the time of completing the IRP, thereby creating a gap in the data. Forecasted emissions show continued and substantial downward trend in emissions—the result of coal-to-gas conversions and the addition of clean resources through the IRP time horizon.

Table 1.4 Historical and forecasted emissions



1. BACKGROUND

Integrated Resource Plan

Idaho Power's resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy and flexible capacity within Idaho Power's service area throughout the 20-year planning period.
2. Ensure the selected resource portfolio balances cost and risk while also considering environmental factors.
3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.
4. Involve the public in the planning process in a meaningful way.

The Integrated Resource Plan (IRP) evaluates a 20-year planning period in which demand is forecasted and additional resource requirements are identified.

Idaho Power relies on current resources, including hydroelectric projects, solar photovoltaic (PV) projects, wind farms, geothermal plants, natural gas-plants, coal-facilities, and energy markets via transmission interconnections. The company's existing supply-side resources are detailed in Chapter 4, while possible future supply-side resources are explored in Chapter 5.

Other resources relied on for planning include demand-side management (DSM) and transmission resources, which are further explored in chapters 6 and 7, respectively. The goal of DSM programs is to achieve cost-effective, energy efficiency savings and provide an optimal amount of peak reduction from demand response (DR) programs. Idaho Power also strives to provide customers with tools and information to help them manage their own energy use. The company achieves these objectives by implementing and carefully managing incentive programs as well as through outreach and education.

Idaho Power's resource planning process evaluates additional stand-alone transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and Idaho Power coordinates transmission planning as a member of NorthernGrid. Idaho Power is obligated under Federal Energy Regulatory Commission (FERC) regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers and Idaho Power retail customers. The delivery of energy, both within Idaho Power's system and through regional transmission interconnections, is of increasing importance for several reasons. First, adequate transmission is essential to achieve cost savings benefits through robust participation in the Energy Imbalance Market (EIM). Second, it is necessary to unlock geographic resource diversity benefits for Variable Energy Resources (VER). The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The IRP Advisory Council (IRPAC) meets regularly during the development of the resource plan, and the meetings are open to the public. Members of the council include staff from the Idaho Public Utilities Commission (IPUC) and Public Utility Commission of Oregon (OPUC); political, environmental, and customer representatives; and representatives of other public-interest groups. Many members of the public also participate in the IRPAC meetings. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2023 IRPAC members can be found in *Appendix C—Technical Report*.

Idaho Power facilitated 12 IPRAC meetings (see *Appendix C—Technical Report*, IRPAC Meeting Schedule and Agenda). With the exception of the introductory meeting, all 2023 IRPAC meetings were conducted virtually, which resulted in increased and more diverse participation of members and the general public. The company received positive feedback from IRPAC members that the virtual forum was logistically easier and aided in the presentation and review of materials.

To further enhance engagement, Idaho Power also maintained an online webpage for stakeholders to submit requests for information and for Idaho Power to provide responses. The webpage allowed stakeholders to develop their understanding of the IRP process, particularly its key inputs, consequently enabling more meaningful stakeholder involvement. The company made presentation slides and other materials used at the IRPAC meetings, in addition to the question-submission portal and other IRP documents, available to the public on its website at idahopower.com/IRP. For the first time as part of the IRP process, Idaho Power included educational resources provided and prepared to help IRPAC members and attendees understand and catch up on industry concepts on its IRP webpage (accessed at the prior link). These resources include information on industry topics and pre-recorded presentations prepared by the National Renewable Energy Laboratory, the United States Energy Information Administration (EIA), the U.S. Department of Energy (DOE), and Idaho Power. A list of acronyms and a directory of Idaho Power employees involved in the process was also posted.

IRP Methodology

The primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over the 20-year planning period while also minimizing costs and risks to customers. This process is completed, and a new plan is produced every two years. To ensure Idaho Power can meet its customers' growing need for energy, the capability of the existing system is included and then resources are added (or removed). Multiple portfolios consisting of varying resource additions (and exits) are produced. Resource additions include supply-side resources like solar generation facilities, while resource exits include coal- and gas-fired resources. Other resource additions include demand-side resources like energy efficiency measures and transmission projects that increase access to energy markets or support integration of renewable resources. The portfolios are then compared, and the portfolio that best minimizes cost and risk is selected in the plan.

Cost

Costs for each portfolio include the capital costs of designing and constructing each resource, including transmission builds and expansions, through the 20-year timeframe of the plan. Operational costs—such as fuel costs, maintenance costs, environmental controls, and the price to purchase and sell energy on the electrical market—are modeled and included to compare the cost effectiveness of each portfolio.

Risk

Typical of long-term planning, uncertainty increases the further into the future one attempts to evaluate. Acknowledging this uncertainty and the risk this creates, the 2023 IRP includes a robust risk analysis and approaches the subject in three ways.

The first risk analysis method evaluates different future scenarios to test the decisions being made, especially in the Near-Term Action Plan window—which is the first five years in the plan (2024–2028). Future scenarios typically include multiple assumptions that combine to define the scenario. To enhance the risk evaluation within the 2023 IRP, the company worked with the IRPAC to develop a variety of unique future scenarios. The company ultimately used these scenarios to test whether the decisions being made within the Near-Term Action Plan window are robust across multiple futures. The future scenarios are as follows:

- High Gas Price–High Carbon Price
- Low Gas Price–Zero Carbon Price
- Constrained Battery Storage
- 100% Clean Energy by 2045
- Additional Large Load
- 100% Clean Energy by 2035

- New Forecasted PURPA[5] resources
- Extreme Weather
- Rapid Electrification
- Constrained Transmission
- Load Flattening

The second method employed by the 2023 IRP is an analysis of stochastic risk. Stochastic analyses help quantify the sensitivity and risk associated with variables over which Idaho Power has little or no control. For more information, see Chapter 10.

The third method of risk analysis, qualitative risk, is used to identify risks that are not easily quantified. A detailed discussion of qualitative risk can be found in Chapter 10.

Modeling

Due to the complexity involved in an analysis that includes a 20-year forecast for energy demand, fuel prices, resource costs and more, Idaho Power uses modeling software to generate and optimize resources selected in portfolios. For the 2023 IRP, the company used AURORA's Long-Term Capacity Expansion (LTCE) platform to generate resource portfolios. As described in Chapter 9—Portfolios, the software evaluates how to cost-effectively meet future needs by selecting resources that are optimized within modeling constraints.

Validation and Verification

In the 2023 IRP, the company employed additional verification tests to ensure the AURORA LTCE model produced an optimized solution within its modeling tolerance. Verification tests validated the most economic portfolio under numerous variations of resources and timing.

Details about the validation and verification process can be found in the Validation and Verification section of *Appendix C—Technical Report*.

Reliability

In addition to AURORA-specific validation and verification, the company measured the reliability of select portfolios using the Loss of Load Expectation (LOLE) methodology to verify that the AURORA-produced portfolios meet Idaho Power's reliability requirements. Idaho Power implements the LOLE methodology through an internally developed Reliability and Capacity Assessment Tool (RCAT), which calculates portfolio Planning Reserve Margins (PRM) and resource Effective Load Carrying Capability (ELCC) values. PRMs and ELCCs from the RCAT are then provided as an input to the AURORA LTCE model. To verify that the translation from

[5] *Public Utility Regulatory Policies Act of 1978* (PURPA)

the RCAT to the AURORA LTCE model produces reliable portfolios, the RCAT calculates annual capacity positions for the select portfolios' resource buildouts to validate that each year in the 20-year planning horizon is in a position of capacity length when the LOLE threshold is 0.1 event-days per year. This verifies that the select portfolios meet Idaho Power's reliability threshold.

An in-depth discussion of the LOLE calculation process can be found in the Loss of Load Expectation sections of *Appendix C—Technical Report*.

Energy Risk Management Policy

While the 2023 IRP addresses Idaho Power's long-term resource needs, near-term energy needs are evaluated in accordance with the company's *Energy Risk Management Policy and Energy Risk Management Standards*. The risk management standards were collaboratively developed in 2002 among Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The risk management standards provide guidelines for Idaho Power's physical and financial hedging and are designed to systematically identify, quantify, and manage the exposure of the company and its customers to uncertainties related to the energy markets in which Idaho Power is an active participant. The risk management standards specify an 18-month load and resource review period, and Idaho Power's Risk Management Committee assesses the resulting operations plan monthly.

2. POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

As a regulated utility, Idaho Power's operations and long-term planning are guided by federal, regional, and state policies and requirements. This chapter addresses the long-standing and new federal policies; Idaho- and Oregon-specific policies and regulations; and new developments in regional energy policy.

Federal Policy & Activities

Hydroelectric Relicensing

As a utility that operates non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses are valid for 30 to 50 years, depending on the size, complexity, and cost of the project.

Hells Canyon Dam.

Idaho Power is currently relicensing two projects: the Hells Canyon Complex (HCC) and American Falls. The HCC is the more significant of the two relicensing efforts.

The HCC provides approximately 70% of Idaho Power's hydroelectric generating capacity and 30% of the company's total generating capacity. The HCC provides clean energy to Idaho Power's system, supporting Idaho Power's long-term clean energy goals. The HCC also provides flexible capacity critical to the successful integration of VERs, which provide low-cost energy and further enable Idaho Power to achieve its clean energy goals.

Idaho Power's HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC has been processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1973*; the *Clean Water Act of 1972* (CWA); and other applicable federal laws. Since issuance of the final environmental impact statement (EIS) (NEPA document) in 2007, FERC has been waiting for Idaho and Oregon to issue a final Section 401 certification under the CWA. The states issued the final CWA 401 certification on May 24, 2019. In July 2019, three third parties filed lawsuits against the Oregon Department of Environmental Quality in Oregon state court challenging the Oregon CWA 401 certification. Two of the lawsuits were consolidated, and Idaho Power intervened in that lawsuit. The parties reached a settlement in September 2021. The court dismissed the third challenge with prejudice. No parties challenged the Idaho CWA 401 certification. FERC will now be able to continue with the relicensing process, which includes consultation under the *Endangered Species Act of 1973*, among other actions.

Efforts to obtain a new, multi-year license for the HCC will likely continue through 2024. Until the multi-year license is issued, Idaho Power continues to operate the project under annual licenses issued by FERC.

After a new multi-year license is issued, further costs will be incurred to comply with the terms of the new license. Because the new license for the HCC has not been issued—and discussions on protection, mitigation, and enhancement packages are still being conducted—Idaho Power cannot determine the ultimate terms of, and costs associated with, any resulting long-term license.

In addition to the relicensing of the HCC, Idaho Power is also relicensing its American Falls hydroelectric project. In February 2023, Idaho Power filed its Final License Application with FERC. The current license expires in February 2025.

Relicensing activities included the following:

- Coordinating the relicensing process
- Consulting with regulatory agencies, tribes, and interested parties on resource and legal matters
- Preparing and conducting studies or analysis on fish; endangered species; terrestrial resources; water quality; recreation; and archaeological resources, among others
- Analyzing data and reporting study results
- Preparing all necessary reports, exhibits, and filings to support ongoing regulatory processes related to the relicensing effort

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement measures imposed as a condition of relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment. As noted earlier, Idaho Power views the relicensing of the HCC as critical to its clean energy goals.

The 2023 IRP assumes that the available capacity and operational flexibility of the HCC and American Falls will be consistent with the most current relicensing proposals and Idaho Power's anticipation of what will be included in a future FERC license. All other hydroelectric facilities are assumed to have available capacity and operational flexibility as outlined in their current FERC licenses.

Recent Executive Orders

In January 2021, the Biden Administration issued several executive orders to establish new federal environmental mandates, revoke several existing executive orders, and require agencies to review regulations related to environmental matters issued by the previous presidential administration. One executive order results in the United States rejoining the Paris Agreement on climate change, which requires commitments to reduce greenhouse gas (GHG) emissions, among other things. A more recent executive order, signed by President Biden on December 8, 2021, seeks to leverage government actions and procurement to further the clean energy transition. Among several directives in the order, is the requirement to achieve net-zero emissions from federal procurement and from overall federal operations by 2050.[6]

Inflation Reduction Act

On August 16, 2022, President Biden signed into law the *Inflation Reduction Act of 2022* (IRA), a federal law intended to curb national inflation by, among other items, investing in domestic energy production and expanding incentives for clean energy. The law includes $783 billion for energy- and climate change-related efforts, notably expanding the type and availability of tax credits for clean energy investment and production. Specifically, the IRA extends the investment tax credit (ITC) for solar projects and now offers this tax credit for standalone storage projects; establishes a nuclear power production credit; and creates broad and technology-neutral investment and production tax credits (PTC) for new clean electricity generation that produces zero or negative GHG emissions.

The amount, duration, and requirements of the incentives vary by type, and each has the potential to unlock additional "bonus" credits for qualifying conditions: domestic manufacturing and delivery of energy to low-income communities.

As with all legislation, the IRA establishes these incentives as new laws, but a variety of government agencies are tasked with implementing and creating access to these incentives. As a result, the 2023 IRP includes elements of the IRA that were understood at the time of developing this long-term plan.

[6] whitehouse.gov/briefing-room/statements-releases/2021/12/08/fact-sheet-president-biden-signs-executive-order-catalyzing-americas-clean-energy-economy-through-federal-sustainability/.

Clean Power Plan

In June 2014, the United States Environmental Protection Agency (EPA) released, under Section 111(d) of the *Clean Air Act of 1970*, a proposed rule for addressing GHG emissions from existing fossil fuel electric generating units. The proposed rule was intended to achieve a 30% reduction in carbon dioxide (CO_2) emissions from the power sector by 2030. In August 2015, the EPA released the final rule under Section 111(d) of the Clean Air Act, referred to as the Clean Power Plan, which required states to adopt plans to collectively reduce 2005 levels of power sector CO_2 emissions by 32% by 2030.

In June 2019, the EPA released the Affordable Clean Energy rule to replace the Clean Power Plan under Section 111(d) of the Clean Air Act for existing electric utility generating units. In August 2019, 22 states sued the EPA in federal appeals court to challenge the Affordable Clean Energy rule. In January 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the Affordable Clean Energy rule in its entirety and directed the EPA to create a new regulatory approach. On February 12, 2021, the EPA issued a memorandum notifying states that it will not require states to submit plans to the EPA under Section 111(d) of the Clean Air Act because the Court vacated the Affordable Clean Energy rule without reinstating the Clean Power Plan.

Cross-State Air Pollution Rule

On March 15, 2023, the EPA pre-published the final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards. The Good Neighbor Plan is intended to address 23 states' obligations to eliminate their contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards under the "good neighbor" or "interstate transport" provision of the Clean Air Act. Nevada is included in this rule; however, Wyoming's inclusion has been deferred pending further review of air quality modeling and analysis. The rule will become effective 60 days after publication in the Federal Register.

Idaho Power has entered discussions with NV Energy on the impact the rule will have on operations at North Valmy. Modeling of North Valmy will include compliance with the Good Neighbor Plan, including a range of nitrogen oxide (NOx) allowances based on the probable split between the partners. Jim Bridger will be modeled with a sensitivity that Wyoming may be included in the Good Neighbor Plan in the future.

Wyoming Round 1 Regional Haze Compliance

On February 14, 2022, Wyoming and PacifiCorp filed a Consent Decree in the Wyoming State District Court, settling potential State compliance claims with the State Implementation Plan (SIP) previously approved for the Jim Bridger Power Plant (Bridger) by the EPA in 2015. The Consent Decree required PacifiCorp to submit a new permit application and a proposed SIP revision within two months, reflecting emission limits consistent with the conversion of Bridger units 1 and 2 to natural gas generation by January 1, 2024. In April 2022, PacifiCorp submitted the new permit application and proposed SIP revision, consistent with the terms of the Consent Decree.

The 2023 IRP modeling includes the natural gas conversion of Bridger units 1 and 2 and considers the monthly emission limits of the Consent Decree. After the natural gas conversion at Bridger units 1 and 2, the monthly emission limits outlined in the Consent Decree will not restrict Bridger operations.

Public Utility Regulatory Policies Act

In 1978, the United States Congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Electricity from Cogeneration and Small-Power Production (CSPP) is often associated with PURPA. Individual states were tasked with establishing Power Purchase Agreement (PPA) terms and conditions, including prices that each state’s utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in Idaho and Oregon, the company must adhere to IPUC rules and regulations for all PURPA facilities located in Idaho, and to OPUC rules and regulations for all PURPA facilities located in Oregon. The rules and regulations are similar but not identical for the two states.

Under PURPA, Idaho Power is required to pay for generation at the utility’s avoided cost, which is defined by FERC as the incremental cost to an electric utility of electric energy or capacity that, but for the purchase from the QF, such utility would generate itself or purchase from another source. The process to request an Energy Sales Agreement for Idaho QFs is described in Idaho Power’s Tariff Schedule 73; and for Oregon QFs, Schedule 85. QFs also have the option to sell energy “as-available” under Idaho Power’s Tariff Schedule 86.

Idaho Policy & Activities

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor’s Office of Energy and Mineral Resources, the Idaho Strategic Energy Alliance (ISEA) helps develop effective and long-lasting responses to existing and future energy challenges. The purpose of the ISEA is to enable the development of a sound energy portfolio that emphasizes the importance of an affordable, reliable, and secure energy supply.

ISEA’s strategy focuses on three foundational elements: 1) maintaining and enhancing a stable, secure, and affordable energy system; 2) determining how to maximize the economic value of Idaho’s energy systems and in-state capabilities, including attracting jobs and energy-related industries and creating new businesses with the potential to serve local, regional, and global markets; and 3) educating Idahoans to increase their knowledge about energy and energy issues.

Idaho Power representatives serve on the ISEA Board of Directors and several volunteer task forces on the following topics:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Baseload resources
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach
- Energy storage
- Transportation

Idaho Energy Landscape

In 2022, the ISEA prepared the *2022 Idaho Energy Landscape Report* to help Idahoans better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.

The *2022 Idaho Energy Landscape Report* concludes, "The strength of Idaho's economy and quality of life for its citizens depend upon access to affordable and reliable energy resources."[7] The report provides information about energy resources, production, distribution, and use in the state. The report also discusses the need for reliable, affordable, and sustainable energy for individuals, families, and businesses, while protecting the environment to achieve sustainable economic growth and maintain Idaho's quality of life.

The report states that low average rates for electricity and natural gas are the most important feature of Idaho's energy outlook. Large hydroelectric facilities on the Snake River and other

[7] 2022-Idaho-Energy-FINAL.pdf. Accessed July 2023.

tributaries of the Columbia River provide the energy and flexibility required to meet the demands of this growing region.

In 2022, hydroelectricity remained the largest source of Idaho's in-state electricity generation, comprising 51%.[8] Low-cost hydroelectricity helps preserve Idaho's low electricity rates and is the cornerstone of Idaho Power's low electricity rates. As the largest utility in the state, Idaho Power's total retail average rate was 32% below the national average in 2022, based on data compiled by the Edison Electric Institute.[9]

Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the management of water resources by local, state, and federal entities, and the administration of water rights by the states within the Snake River Basin. In addition to a FERC license and other associated state and federal permits, Idaho Power must also secure and maintain state water rights for the operation of these projects.

The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects. Idaho Power is dedicated to the vigorous defense of its water rights. The company's ongoing participation in various efforts to develop sustainable water rights-related policy and studies is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River and to ensure the state's acknowledgment of the value of hydroelectric power to Idaho's economy.

Idaho Power, along with other Snake River Basin water-right holders, was engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and the extent of water rights in the Snake River Basin. Idaho Power filed claims for all its hydroelectric water rights in the SRBA. Because of the SRBA, Idaho Power's water rights were adjudicated, resulting in the issuance of partial water-right decrees. The Final Unified Decree for the SRBA was signed on August 25, 2014.

The initiation of the SRBA resulted from the Swan Falls Agreement, which was entered into by Idaho Power and the governor and attorney general of the State of Idaho in October 1984. The Swan Falls Agreement resolved a struggle over the company's water rights at the Swan Falls Hydroelectric Project (Swan Falls Project). The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled Idaho Power to

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[8] eia.gov/state/analysis.php?sid=ID

[9] Edison Electric Institute, *Typical Bills and Average Rates Report Winter 2023*.

a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The Swan Falls Agreement placed the portion of the company's water rights beyond the minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and Idahoans. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007 because of disputes about the meaning and application of the Swan Falls Agreement. The company asked the court to resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated Idaho Power's hydroelectric water rights to managed aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying the water rights held in trust by the State of Idaho are subject to subordination to future upstream beneficial uses, including managed aquifer recharge. The settlement also committed the State of Idaho and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Pursuant to the Framework, Idaho Power, the Idaho Water Resource Board (IWRB), and the State of Idaho actively work cooperatively to explore resolution of issues as members of the Swan Falls Implementation Group.

In 2014, Idaho Power expanded its long-standing cloud-seeding program, which began in the Payette basin in 2003. The expansion of cloud-seeding activities to the Boise and Wood River basins was conducted in collaboration with basin water users and the IWRB. Today, Idaho Power financially supports and operates its cloud-seeding program in the Payette and operates and collaboratively financially supports programs in the Upper Snake, Boise, and Wood River basins. Along with augmenting surface flows in the Snake River basins, cloud seeding in the Wood River Basin, along with the Upper Snake River Basin, benefits the Eastern Snake River Plain Aquifer (ESPA) Comprehensive Aquifer Management Plan implementation through additional water supply for natural and managed aquifer recharge.

In recent years, water management activities for the ESPA have been driven by the 2015 Settlement Agreement between the Surface Water Coalition and the Idaho Ground Water Appropriators. This agreement had settled a call by the Surface Water Coalition against groundwater appropriators for the delivery of water to its members at the Minidoka and Milner dams. The agreement had provided a plan for the management of groundwater resources on the ESPA, with the goal of improving aquifer levels and spring discharge upstream of Milner Dam. The plan provided short- and long-term aquifer level goals that must be met to ensure a sufficient water supply for the Surface Water Coalition. The plan also references ongoing management activities, such as aquifer recharge.[10]

On November 4, 2016, the Idaho Department of Water Resources Director signed an order creating a Ground Water Management Area (GWMA) for the ESPA. The Director told the Idaho Water Users Association at their November 2016 Water Law Seminar:

> By designating a groundwater management area in the Eastern Snake Plain Aquifer region, we bring all of the water users into the fold—cities, water districts and others—who may be affecting aquifer levels through their consumptive use. […] As we've continued to collect and analyze water data through the years, we don't see recovery happening in the ESPA. We're losing 200,000 acre-feet of water per year.

The director said creating a GWMA will embrace the terms of a historic water settlement between the Surface Water Coalition and groundwater users, but the GWMA for the ESPA will also seek to bring other water users under management who have not joined a groundwater district—including some cities. In 2023, an advisory committee was formed and tasked with developing a groundwater management plan to address water supply issues impacting the ESPA. Idaho Power participates as an advisory committee member.

On October 21, 2022, the director of the Idaho Department of Water Resources signed an order re-establishing a moratorium on the issuance of new consumptive water rights permits from surface and groundwater tributary to the Snake River upstream from Milner Dam, as well as from Milner Dam to King Hill. The order also created a new moratorium on the issuance of new consumptive water right permits from surface and groundwater tributary to the Snake River between King Hill and Swan Falls Dam. In issuing the moratorium, the director concluded that additional appropriation of surface or groundwater upstream of Swan Falls could lead to a violation of the minimum streamflow rights of 3,900 cfs and 5,600 cfs at the Murphy gage. Effectively, the moratorium order acknowledges that water supplies are fully allocated above Swan Falls Dam, and that a moratorium is necessary to protect the minimum streamflow rights resulting from the Swan Falls Agreement. The moratorium is important to Idaho Power because it demonstrates the role that the State of Idaho has in protecting a minimum water supply for the company's hydroelectric system.

[10] In 2023, it became apparent that the goals set in the agreement would not be achieved; however, the settlement agreement provides the framework for modeling future management activities on the ESPA. These management activities are included in the modeling of hydropower production through the IRP planning horizon.

Oregon Policy & Activities

State of Oregon 2022 Biennial Energy Report

In 2017, the ODOE introduced House Bill (HB) 2343, which required ODOE to develop a new biennial report to inform local, state, regional, and federal energy policy development and energy planning and investments. The *2022 Biennial Energy Report*[11] provides foundational energy data about Oregon and examines the existing policy landscape while identifying options for continued progress toward meeting the state's goals in the areas of climate change, renewable energy, transportation, energy resilience, energy efficiency, and consumer protection.

Renewable energy continues to make up an increasing share of Oregon's energy mix each year. With the increase in renewable energy sources, other resources in the electricity mix have changed as well. The amount of coal included in Oregon's resource mix declined from 32% in 2012 to 26% in 2020. Natural gas—a resource that can help manage the hourly variation of renewable resources and smooth out seasonal hydropower variation—has steadily increased its share of Oregon's resource mix from 12% in 2012 to 21.5% in 2020.

The main theme of the 2022 biennial report was Oregon's transition to a low-carbon economy. According to the report, achieving Oregon's energy and climate goals, while protecting consumers, will take collaboration among state agencies; policymakers; state and local governments; and private-sector business and industry leaders.[12]

Oregon Renewable Portfolio Standard and Emissions Reduction Requirements

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established a Renewable Portfolio Standard (RPS) for electric utilities and retail electricity suppliers. Under the Oregon RPS, Idaho Power is classified as a smaller utility because the company's Oregon customers represent less than 3% of Oregon's total retail electric sales. In 2021 per EIA data, Idaho Power's Oregon customers represented 1.3% of Oregon's total retail electric sales. As a smaller utility in Oregon, Idaho Power will likely have to meet a 5% RPS requirement beginning in 2025.

In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25% by 2025 to 50% renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change. Additionally, the Oregon Legislature in 2021 passed HB 2021, which sets GHG emissions reduction requirements associated with electricity sold to utility customers. Idaho

[11] energyinfo.oregon.gov/ber. Accessed April 2023.

[12] ODOE, *2022 Biennial Energy Report*.

Power is exempt from the conditions of this bill, as the company has fewer than 25,000 retail customers in Oregon.

The State of Idaho does not currently have an RPS.

Oregon Community Solar Program

In 2016, the Oregon Legislature enacted Senate Bill 1547, which requires the OPUC to establish a program for the procurement of electricity from community solar projects. Community solar projects provide electric company customers the opportunity to share in the costs and benefits associated with the electricity generated by solar PV systems, as owners of or subscribers to a portion of the solar project.

Since 2016, the OPUC has conducted an inclusive implementation process to carefully design and execute a program that will operate successfully, expand opportunities, and have a fair and positive impact across electric company ratepayers. After an inclusive stakeholder process, the OPUC adopted formal rules for the Community Solar Pilot program on June 29, 2017, through Order No. 17-232, which adopted Division 88 of Chapter 860 of the Oregon Administrative Rules. The rules also define the program size, community solar project requirements, program participant requirements, and details surrounding the opportunity for low-income participants, as well as information regarding on-bill crediting.

Under the Oregon Community Solar Program rules, Idaho Power's initial capacity tier is 3.3 MW. As of completion of the 2023 IRP, Idaho Power has executed all the necessary agreements with Verde Light, a 2.95 MW project that intends to participate in the community solar program, with an estimated in-service date of late 2024. The proposed 2.95 MW project will use all but 305 kilowatts (kW) of Idaho Power's initial capacity allocation.

Additionally, Order No. 17-232 requires Idaho Power to 1) include all energized community solar projects participating in the community solar program in its generation mix included in its IRP and 2) include forecasts of market potential for community solar projects when assessing the load-resource balance in the IRP. Because the potential project is not planning to be fully operational until late 2024, the resource has not been included in this IRP. Once operational, the project will be included as part of the generation mix in future IRP cycles.

Regional Policies & Activities

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is the first regional reliability planning and compliance program in the western United States. At its simplest, WRAP is a region-wide planning process that assesses resource adequacy across the footprint and seeks to increase regional reliability while providing economic benefits associated with regional coordinated planning to participants. WRAP facilitates a reliability program that allows for available resources to be shared among participants during short-term periods of resource deficiency. The goal of this program is to maintain reliability across all participants' systems over the course of an operating season in which some participants may experience peak load conditions or extreme weather events. WRAP is being developed through a collaborative, participant-driven process that is facilitated by the Western Power Pool (WPP). WPP will be the program operator of the WRAP, including managing implementation of the WRAP rules and tariff.

To facilitate the sharing of resources among participants, WRAP is organized into two parts over two seasons (summer and winter): an advanced viewing of resources—called the forward showing—and an operations phase during which resources can be shared in times of need. Each season has its own forward showing and operations program, and each participant is individually responsible for complying with the forward showing and operations program requirements.

On August 31, 2022, WPP filed a tariff with FERC requesting approval of WRAP and its proposed framework for implementation and operation.[13] On February 10, 2023, FERC approved the WRAP tariff and underscored the importance of a regional program and the enhanced reliability and resource adequacy that WRAP would bring.[14] Following the tariff's approval, the WPP Board of Directors approved the slate of nominees to serve on the new Independent Board of Directors, which includes one board chairperson and four board members with various executive and consultative backgrounds in the electric industry.[15] With the WRAP tariff approved, the program can now transition from a non-binding to a fully-binding program. This transition will occur in phases, with binding participation starting as early as Summer 2025 or as late as Summer 2028. While participation in WRAP is voluntary, binding participants must meet capacity and delivery requirements and pay participation costs.

In December of 2022 and January of 2023, WPP received formal commitments from 20 participants, including Idaho Power, supporting a move forward with the next phases of WRAP. On December 19, 2022, Idaho Power announced its plans to move forward with the non-binding phase of WRAP.[16] To date, Idaho Power has participated in WRAP's non-binding,

[13] ER22-2762, Northwest Power Pool submits tariff filing per 35.1: Western Power Pool Western Resource Adequacy Program Tariff (submitted August 31, 2022).

[14] FERC, ER22-2762-000 National Order, p. 10. ("Through increased coordination, we find that the WRAP has the potential to enhance resource adequacy planning, provide for the benchmarking of resource adequacy standards, and more effectively encourage the use of western regional resource diversity compared to the status quo.")

[15] WPP, Western Power Pool Approves Nominees for New Independent Board of Directors (February 21, 2023).

[16] Idaho Power news release, "Idaho Power Moves Forward with Regional Energy Adequacy Group," December 19, 2022.

forward-showing program. Idaho Power submitted forward-showings for the winter 2022/2023, summer 2023, and winter 2023/2024 seasons.

In June 2023, Idaho Power and the other committed WRAP participants commenced the initial account and connectivity testing in preparation for the first non-binding operational phase of the program.

Please see the Western Resource Adequacy Program Modeling section in *Appendix C—Technical Report* for details on how Idaho Power modeled WRAP benefits in the 2023 IRP.

3. CLEAN ENERGY & CLIMATE CHANGE

Idaho Power recognizes the need to assess the impacts of climate change on industry, customers, and long-term planning. The company undertakes a variety of analysis exercises and impact evaluations to understand and prepare for climate change. This chapter of the IRP focuses on identifying climate-related risks, discussing the company's approach to monitoring and mitigating identified risks, and examining climate-related risk considerations in the IRP.

In a climate change assessment, it is important to underscore the distinction between mitigation and adaptation. Climate change mitigation refers to efforts associated with reducing the severity of climate change, most commonly through the reduction of GHG emissions, primarily CO_2. In contrast, climate change adaptation involves understanding the scope of potential physical and meteorological changes that could result from climate change and identifying ways to adapt to such changes. Idaho Power's climate change risk assessment examines both mitigation and adaptation in the sections below.

Climate Change Mitigation

A Cleaner Energy Mix

Combined with the energy purchased from PPAs and PURPA projects, Idaho Power's resource mix was approximately 47% clean in 2022 (see below).[17] The company's clean generation mix is primarily driven by hydropower. Idaho Power experienced the worst two-year drought in the history of the service area from 2021 to 2022, which reduced Idaho Power's clean production in those years.

The 2022 energy mix notably includes more than 1,200 megawatts (MW) of power purchase contracts for renewable energy (primarily, but not exclusively, PURPA projects): 725 MW of wind, 316 MW of solar, 150 MW of small hydropower, and 35 MW of geothermal.

[17] The company sells the RECs associated with renewable energy, meaning that the overall mix does not represent the energy delivered to customers.

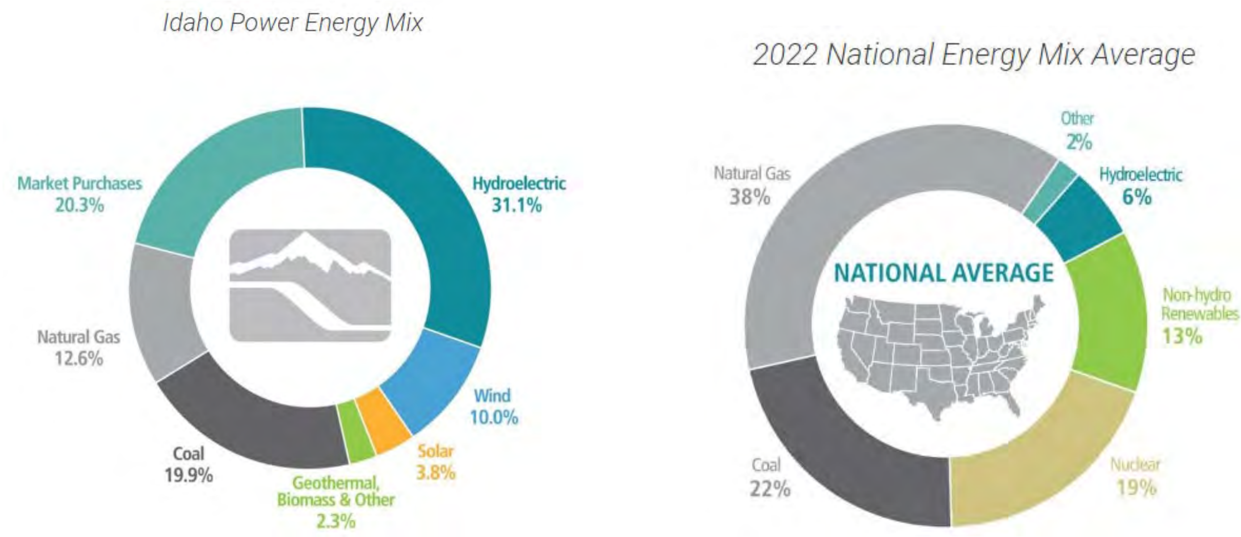

Figure 3.1 Idaho Power's 2022 energy mix compared to the national average

The company's plan to cost-effectively exit participation in coal-fired generation resources is evident in the 2023 IRP's Preferred Portfolio and Near-Term Action Plan. The addition of renewable resources over the 20-year planning horizon, combined with the completion of the Boardman to Hemingway (B2H) transmission line in 2026, will significantly change the company's energy mix in the future to include primarily clean resources.

Our Clean Energy Goal—Clean Today. Cleaner Tomorrow.®

In March 2019, Idaho Power announced a goal to provide 100% clean energy by 2045. This goal furthers Idaho Power's legacy as a leader in clean energy. The key to achieving this goal of 100% clean energy is the company's existing backbone of hydropower—our largest energy source—as well as the plan contained in the Preferred Portfolio to continue reducing carbon emissions by ending reliance on coal plants by 2030.

The Preferred Portfolio identified in the 2023 IRP reflects a clean mix of generation and transmission resources that ensures reliable, affordable energy. Achieving our 100% clean energy goal by 2045 will require additional technological advances and reductions in cost, as well as a continued focus on EE and DR programs. As it has for more than a decade, the IRPAC will continue to play a fundamental role in updating the IRP every two years, including analyzing new and evolving technologies to help the company on its path toward a cleaner tomorrow while providing low-cost, reliable energy to our customers.

Clean Energy Your Way

On August 15, 2023, the IPUC approved Idaho Power's proposal to expand optional customer clean energy offerings through the Clean Energy Your Way (CEYW) Program. Idaho Power has long supported customers' individual goals and initiatives to achieve clean energy through various program offerings, as well as becoming one of the first investor-owned utilities to proactively establish a 100% clean energy goal by 2045.

CEYW will allow the company to better meet the needs of the growing number of customers and communities pursuing or exploring sustainability targets, such as powering their operations on 100% renewable energy by the end of the decade—if not sooner.

CEYW includes three options for customers:

1. CEYW—Flexible, a Renewable Energy Certificate (REC) purchase program available to all customers in Idaho and Oregon
2. CEYW—Subscription, a forthcoming subscription option for customers of all sizes in Idaho
3. CEYW—Construction, an option for the company's largest customers in Idaho

Clean Energy Your Way—Flexible

The Flexible offering is a renaming of the company's Green Power Program. Business and residential customers can continue to purchase RECs in blocks of 100 kilowatt-hours (kWh) or covering 100% of their usage.

Clean Energy Your Way—Subscription

The IPUC authorized the company to move to the next phase of developing a subscription program, including identification of a resource, as well as program details and pricing. The CEYW—Subscription offering will provide opportunities for business and residential customers in Idaho to receive an amount of renewable energy equal to 25, 50, 75, or 100% of their historic average annual energy use by subscribing to a new renewable resource. Subscription terms will be intended to provide customers the ability to opt-in and opt-out based on their individual preferences. Terms for residential customers could be as short as monthly, and terms for business customers would range from 5 to 20 years.

In late 2023 and early 2024, Idaho Power will work with stakeholders and customers to develop the CEYW-Subscription offering, and then file an application with the IPUC to approve the program as proposed.

Clean Energy Your Way—Construction

The CEYW—Construction offering, now approved, allows industrial customers (Special Contract and Schedule 19 customers) in Idaho to partner with Idaho Power to develop new renewable resources through a long-term arrangement. Customers can work with Idaho Power and provide input on the size, location, and type of renewable project (i.e., wind or solar) to meet their individual requirements. The new renewables must connect to Idaho Power's system, but customers are able to claim the renewable attributes as their own.

This offering requires detailed, negotiated contracts between an Idaho customer and Idaho Power that will require individual approval by the IPUC. In the 2023 IRP, two such CEYW—Construction projects have been factored into portfolio modeling—Brisbie, LLC's supporting renewables and Micron's Black Mesa solar project.

Details about the modeling inputs of the CEYW Program can be found in the Loss of Load Expectation sections of *Appendix C—Technical Report*.

Idaho Power Carbon Emissions

Limiting the impact of climate change requires reducing GHG emissions, primarily CO_2. Idaho Power's CO_2 emissions from generating resources levels have historically been below the national average for the 100 largest electric utilities in the United States, both in terms of emissions intensity (pounds per megawatt-hour [MWh] generation) and total CO_2 emissions (tons). The overall declining trend of carbon demonstrates Idaho Power's commitment to reducing emissions. This is shown in the Figure 3.2 graph with the light green dashed line indicating the long-term trend and the dark green solid line indicating the actual annual amounts.

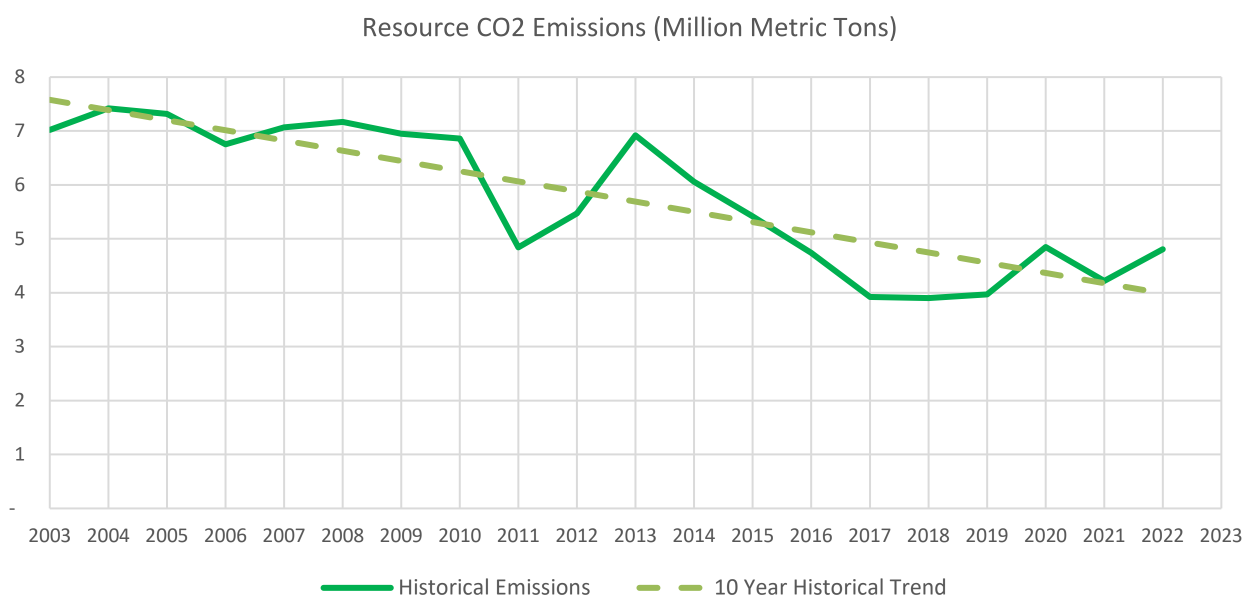

Figure 3.2 Estimated Idaho Power CO_2 emissions

Idaho Power is working to reduce the amount of CO_2 emitted from energy-generating sources. Since 2009, the company has met various voluntary goals to realize its CO_2 reductions. From 2010 to 2022, Idaho Power reduced carbon emissions by an average of 29% compared to 2005. The general trend continues to be downward as Idaho Power exits coal generation facilities and adds clean resources. The uptick in 2020 correlates with low water supply, increased demand for electricity, and market conditions.

Generation and emissions from company-owned resources are included in the CO_2 emissions intensity calculation. Idaho Power's progress toward achieving this intensity reduction goal and additional information on Idaho Power's CO_2 emissions are reported on the company's website. Information is also available through the Carbon Disclosure Project at cdp.net.

The portfolio analysis performed for the 2023 IRP assumes carbon emissions are subject to a per-ton cost of carbon. The carbon cost forecasts are provided in Chapter 9—Portfolios, while the projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 10—Modeling Analysis.

Climate Change Adaptation

As noted earlier, climate change adaptation relates to steps or measures that may need to be taken to adapt to a changing climate. To understand what these steps might be first requires understanding the potential regional impacts of climate change that Idaho Power may experience. To this end, Idaho Power stays current on climate change research and analysis both generally and specific to the Pacific Northwest. The sixth assessment report from the United Nations' Intergovernmental Panel on Climate Change (IPCC) states "Human-induced climate change is already affecting many weather and climate extremes in every region across the globe. Evidence of observed changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones… has strengthened."[18]

More regionally focused studies have assessed the potential impact of climate change on the Pacific Northwest. The Fourth National Climate Assessment[19] and the River Management Joint Operating Committee[20] addressed water availability in the region under multiple climate change and response scenarios. Both reports highlight the uncertainty related to future climate projections. However, many of the model projections show warming temperatures and increased precipitation into the future.

In the 2023 IRP, Idaho Power approached climate change risk in two ways: through adjusted modeling inputs and scenarios and then with specific scenarios to understand portfolio impacts as a result of potential future climate change policies. Both approaches are summarized below and detailed in later chapters of this report.

Risk Identification and Management

Identification of and response to specific risks are managed via Idaho Power's annual Enterprise Risk and Compliance Assessment, which includes a robust review of current and emerging

[18] P. 8, ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM_final.pdf.

[19] nca2018.globalchange.gov/.

[20] bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx.

regulations and external factors impacting the company's internal operations in the areas of technology, legal, market, weather, reputation, and safety, among other risks. Management of each risk is identified and can include internal risk oversight by an internal department, committee, internal or external auditor process review, and Board of Directors oversight.

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

Weather Risk

Changing and severe weather conditions, such as increased frequency and severity of storms, lightning, droughts, heat waves, fires, floods, snow loading, and other extreme weather events can adversely affect Idaho Power's operations. These events have the potential to damage transmission, distribution, and generation facilities; cause service interruptions and extended outages; increase costs and other operating and maintenance expenses—including emergency response planning and preparedness expenses—and limit Idaho Power's ability to meet customer energy demand.

Idaho Power's Atmospheric Science group—in collaboration with Boise State University, the Idaho National Laboratory (INL) and the Idaho Water Resources Board—worked together in 2020 to advance high-performance computing within Idaho. This public–private partnership benefits Idaho Power customers by providing a cost-effective, high-performance computing system to run complex weather models and conduct research to refine weather forecasting capabilities. The company expects this system to help the company improve the integration of renewable energy sources into the electrical grid, help Idaho Power manage the company's hydroelectric system and cloud-seeding operations, and better forecast severe weather conditions.

Idaho Power modeled an Extreme Weather Scenario to capture the impacts of extreme and changing weather conditions as part of the 2023 IRP analysis. The results can be reviewed in Chapter 10.

Wildfire Risk

In recent years, the Western United States has experienced an increase in the frequency and intensity of wildland fires (wildfires). Several factors have contributed in varying degrees to this trend including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors.

The risk of more extensive or worsening wildfires is linked to weather-related climate risk. To manage wildfire-related risk, Idaho Power has developed a Fire Potential Index (FPI) tool based on original work completed by San Diego Gas and Electric, the United States Forest Service, and the National Interagency Fire Center and modified for Idaho Power's service area in Idaho and Oregon.

This tool is designed to support operational decision-making to reduce fire threats and risks. The FPI converts environmental, statistical, and scientific data into an easily understood forecast of the short-term fire threat that could exist for different geographical areas across Idaho Power's service area. The FPI is issued for a seven-day period during wildfire season to provide for planning of upcoming events by Idaho Power personnel and contractors.

The FPI reflects key variables, such as the state of native vegetation across the service area, fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value, and those individual numeric values are summed to generate a Fire Potential value from zero to 16. That final value indicates the degree of fire threat expected for each of the seven days included in the forecast. Green, Yellow, or Red FPI scores reflect low, medium, and high levels of weather-related risk, respectively. The FPI is discussed in greater detail, along with the company's full list of wildfire mitigation measures, in Idaho Power's Wildfire Mitigation Plan (WMP). The WMP is updated annually in advance of each fire season.[21]

Wildfires can cause a wide range of direct and indirect harms, from community damage to air quality and wildlife degradation, reduced recreation access, and power outages. Idaho Power's attention to safety and reliability starts with the quality of its equipment, such as power lines, poles, substations and transformers. The company designs and builds its equipment to meet or exceed industry standards, monitors the ongoing equipment condition, and works hard to maintain the company's infrastructure.

With these goals in mind, Idaho Power has implemented an enhanced vegetation management program to keep trees and other plants away from its lines. The company's vegetation management efforts are applied across its service area and its transmission corridors. This work includes pruning and, if necessary, removing trees, with a higher level of attention in identified zones where wildfire risk is highest. Additionally, in Idaho, a sterilant is applied around select power poles to keep plants from growing nearby. These actions have proved successful in saving poles and lines during wildfire events.

[21] docs.idahopower.com/pdfs/Safety/2022Wildfire%20MitigationPlan.pdf

Water and Hydropower Generation Risk

Factors contributing to lower hydropower generation can increase power supply costs as the company derives a significant portion of its power supply from its hydropower facilities.

Specific programs the company has implemented to responsibly manage water use include working with federal and state government agencies to monitor key water supply indicators (e.g., snow water equivalent, precipitation, temperature); conducting cloud seeding; monitoring surface and groundwater flows; and producing short- and long-range streamflow forecasts to inform the company's water operations.

Water supply within the Snake River Basin is primarily snowpack driven. To increase the amount of snow that falls in drainages that feed the Snake River—subsequently benefiting hydropower generation, irrigation, recreation, water quality and other uses—Idaho Power collaboratively conducts a successful cloud-seeding program in the Snake River Basin. Another significant source of water for Idaho Power's hydro system is the ESPA. This aquifer covers approximately 10,800 square miles in southern Idaho and supports significant economic activity in the agricultural sector as well as other beneficial uses. For much of the year, the ESPA comprises the majority of the water supply from Milner Dam to Swan Falls Dam via springs that discharge from the aquifer to the Snake River. On an annual basis, discharge from the ESPA accounts for 40% of the water supply for the HCC. In dry years and during baseflow conditions in the summer, the aquifer accounts for well over 50% of the water supply for Idaho Power's hydroelectric system. The aquifer has been in a state of general decline over the past several decades. Climate change and other developments on the ESPA could increase demands on groundwater resources, which could ultimately impact hydropower production on Idaho Power's system.

Idaho Power stays current on the rapidly developing climate change research in the Pacific Northwest. The recently completed River Management Joint Operating Committee Second Edition Long-Term Planning Study climate change study shows the natural hydrograph could see lower summer base flows, an earlier shift of the peak runoff, higher winter baseflows, and an overall increase in annual natural flow volume. For Idaho Power's hydro system, the findings support that upstream reservoir regulation significantly dampens the effects of this shift in natural flow to Idaho Power's system. Furthermore, the studies indicate Idaho Power could see July–December regulated streamflow relatively unaffected and January–June regulated streamflow increasing over the 20-year planning period.

Policy Risk

Changes in legislation, regulation, and government policy may have a material impact on Idaho Power's business in the future. Specific legislative and regulatory proposals and recently enacted legislation that could have a material impact on Idaho Power include, but are not limited to, tax reform, utility regulation, carbon-reduction initiatives, infrastructure renewal programs, environmental regulation, and modifications to accounting and public company reporting requirements.

Policy-related risk is addressed in a number of ways in Idaho Power's long-term planning. For each IRP, the company models existing policies, including known expiration or sunset dates. Idaho Power does not model specific policies to which it is not subject. For example, the Oregon Legislature's HB 2021 sets emissions reduction standards for electric utilities, but Idaho Power is exempt because it has fewer than 25,000 retail customers in its Oregon service area. As a result, the company did not model HB 2021 requirements for Idaho Power's portfolio.

At the time of the 2023 IRP, state-level climate policies did not exist in Idaho and did not apply to Idaho Power in Oregon. Similarly, federal climate legislation has not been passed by Congress. However, the company believes that climate- and emissions-related policies will emerge in future years. To account for this expected future, the company models multiple scenarios with varying prices on carbon. These scenarios are detailed in Chapter 9 of this report.

Modeling Climate Risks in the IRP

While the above referenced climate-related risks are addressed and accounted for in different operational ways by Idaho Power, the company also extended climate-related risk assessment to the 2023 IRP. Specifically, the company conducted additional scenarios to explore the impact these events would have on Idaho Power's system. These scenarios are summarized below and detailed in Chapter 9—Portfolios.

The company conducted two Rapid Electrification scenarios at the request of IRPAC members. These scenarios were developed to determine what kind of adjustments would need to be made to accommodate a very rapid transition toward electrification. This rapid transition includes increasing the electric vehicle forecast and the penetration of electric heat pumps for building heating and cooling each by a factor of ten. This aggressive forecast assumes 1.3 million electric vehicles (compared to 180,000 in the planning forecast) as well as adoption of an 80% penetration of heat pump technology at residences within the company's service area by 2043. New for the 2023 IRP, this scenario also includes a bifurcation to evaluate the impact of heat pump adoption as predominantly air source or geothermal.

The Extreme Weather scenario includes an increased demand forecast associated with extreme temperature events and a variable supply of water from year to year.

Idaho Power assessed the risk associated with carbon regulation in two ways. First, to model risk associated with carbon regulation, Idaho Power developed "100% Clean by 2035" and "100% Clean by 2045" scenarios, which assume a legislative mandate to move toward 100%

clean energy by the years 2035 and 2045, respectively. Additionally, the company developed portfolios that alternately assume high and zero carbon price adders to compare them to the portfolios built under the planning case.

By considering the above scenarios and varying assumptions, the 2023 IRP was able to assess possible risk associated with both mitigation and adaptation to climate change.

4. IDAHO POWER TODAY

Customer Load and Growth

Residential construction growth in southern Idaho.

Twenty-five years ago in 1998, Idaho Power served approximately 372,000 customers in Idaho and Oregon. In 2022, Idaho Power served nearly 618,000 customers. Firm peak-hour load increased from 2,535 MW to 3,751 MW in 2021. On June 30, 2021, the peak-hour load reached 3,751 MW—the system peak-hour record.

Average firm load increased from 1,491 average MW (aMW) to 1,947 aMW in 2022 (load calculations exclude the load from the former special contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 4.1 and Table 4.1. The data in Table 4.1 suggests each new customer adds nearly 6 kW to the peak-hour load and over 3 average kW (akW) to the average load.

Idaho Power anticipates adding approximately 11,400 customers each year throughout the 20-year planning period. The anticipated load forecast for the entire system predicts summer peak-hour load requirements will grow approximately 80 MW per year, and the average-energy requirement is forecast to grow about 50 aMW per year. More detailed customer and load forecast information is presented in Chapter 8 and in *Appendix A—Sales and Load Forecast*.

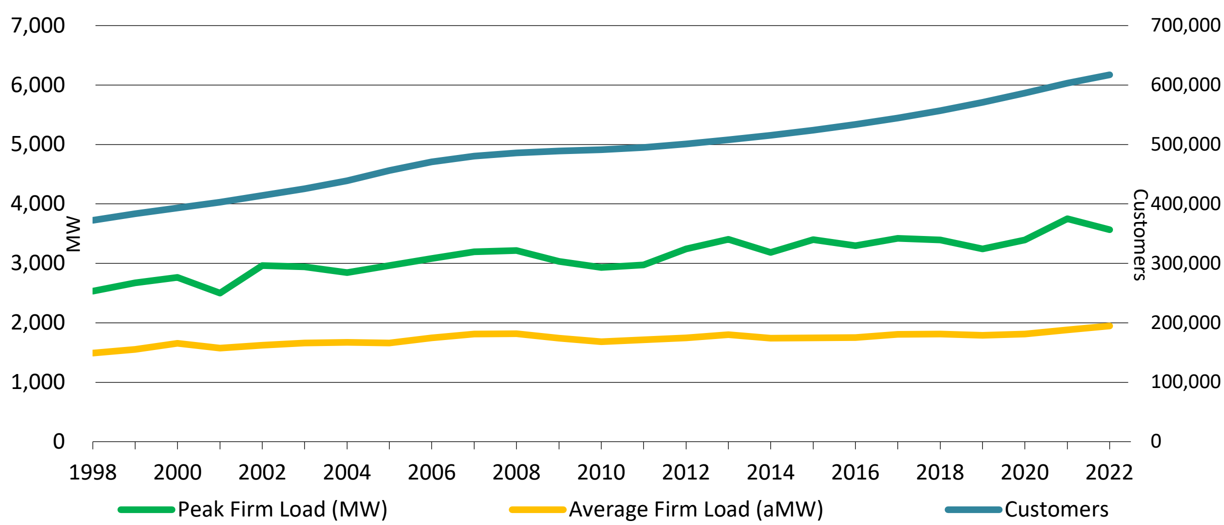

Figure 4.1 Historical load and customer data

Table 4.1 Historical load and customer data

Year	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1998	2,535	1,491	372,464
1999	2,675	1,552	383,354
2000	2,765	1,654	393,095
2001	2,500	1,576	403,061
2002	2,963	1,623	414,062
2003	2,944	1,658	425,599
2004	2,843	1,671	438,912
2005	2,961	1,661	456,104
2006	3,084	1,747	470,950
2007	3,193	1,810	480,523
2008	3,214	1,816	486,048
2009	3,031	1,744	488,813
2010	2,930	1,680	491,368
2011	2,973	1,712	495,122
2012	3,245	1,746	500,731
2013	3,407	1,801	508,051
2014	3,184	1,739	515,262
2015	3,402	1,748	524,325
2016	3,299	1,750	533,935
2017	3,422	1,807	544,378
2018	3,392	1,810	556,926
2019	3,242	1,790	570,953
2020	3,392	1,809	586,565
2021	3,751	1,881	602,983
2022	3,568	1,947	617,243

[1] Year-end residential, commercial, and industrial count plus the maximum number of active irrigation customers.

2022 Energy Sources

Idaho Power's energy sources for 2022 are shown in Figure 3.1. Even in a drought year, hydroelectric production from company-owned projects was the largest single source of energy at about 31% of the total. Coal contributed about 20%, and natural gas generation contributed about 13%. Renewable resources were 10% from wind, 4% from solar, and 2% from geothermal, biomass, and other—which combined with hydroelectric—accounted for 47% of total generation. Market purchases accounted for the remainder of the mix at roughly 20%.

While Idaho Power receives production from PURPA and PPA projects, the company sells the RECs it receives associated with the production.

Existing Supply-Side Resources

Table 4.2 shows all of Idaho Power's existing company-owned resources, plant capacities, and general locations.

Table 4.2 Existing resources

Resource	Type	Capacity* (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	675.0	Hells Canyon
C.J. Strike	Hydroelectric	82.8	Mid-Snake
Cascade	Hydroelectric	12.4	North Fork Payette
Clear Lake	Hydroelectric	2.5	South Central Idaho
Hells Canyon	Hydroelectric	391.5	Hells Canyon
Lower Malad	Hydroelectric	13.5	South Central Idaho
Lower Salmon	Hydroelectric	60.0	Mid-Snake
Milner	Hydroelectric	59.4	Upper Snake
Oxbow	Hydroelectric	190.0	Hells Canyon
Shoshone Falls	Hydroelectric	14.7	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	6.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A & B	Hydroelectric	34.5	Mid-Snake
Jim Bridger	Coal	707.0	Southwest Wyoming
North Valmy	Coal	134.0	North Central Nevada
Langley Gulch**	Natural Gas—CCCT	299.0	Southwest Idaho
Bennett Mountain**	Natural Gas—SCCT	176.0	Southwest Idaho
Danskin**	Natural Gas—SCCT	241.0	Southwest Idaho
Salmon Diesel	Diesel	5.5	Eastern Idaho
Hemingway BESS	Battery Energy Storage	80.0	Southwest Idaho
Black Mesa BESS	Battery Energy Storage	40.0	Southwest Idaho
Total existing plant capacity		**3,481.3**	

*Capacity as reported in FAC-008 Normal Ratings

** Capacity (MW) at International Standards Organization (ISO) reference temperature of 59F

The following sections describe Idaho Power's existing supply-side resources and long-term power purchase contracts.

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,798.8 MW and median annual generation equal to approximately 820 aMW, or 7.2 million MWh (1991–2020).

Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the HCC in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 70% of Idaho Power's annual hydroelectric generation and enough energy to meet over 30% of the energy demand of retail customers. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load following capability.

Idaho Power operates the HCC to comply with the existing annual FERC license, as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements is the Fall Chinook Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

Brownlee Reservoir is the main HCC reservoir and Idaho Power's only reservoir with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equates to approximately 1 million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5% and 1% of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although its primary purpose is to provide a stable power source, Brownlee Reservoir is also used for system flood risk management, recreation, and the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood risk management on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood risk management guidance from the United States Army Corps of Engineers as required in the existing FERC license.

After flood risk management requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie.

The United States Bureau of Reclamation releases water from its storage reservoirs in the Snake River Basin above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake River (mid-Snake) projects, with all the flow augmentation eventually passing through the HCC before reaching the FCRPS projects. Idaho Power works with federal and state partners and other stakeholders to pass these federal flow augmentation releases without delay through the HCC.

As part of a 2005 interim HCC relicensing agreement, Idaho Power agreed to provide up to 237,000 acre-feet of water from Brownlee Reservoir for flow augmentation, in addition to the federal flow augmentation releases. Idaho Power uses its best efforts to hold Brownlee Reservoir at or near full elevation (approximately 2,077 feet above mean sea level) through June 20. Thereafter, Brownlee Reservoir is drafted to an elevation of 2,059 feet (releasing up to 237,000 acre-feet) by August 7. Although the portion of the 2005 interim agreement relating to flow augmentation releases has expired, Idaho Power continues to provide these flow augmentation releases annually. Idaho Power anticipates the Brownlee flow augmentation targets to be included in the upcoming FERC license.

Brownlee Reservoir's releases are managed to maintain operationally stable flows below Hells Canyon Dam in the fall because of the Fall Chinook Program. The stable flow is set at a level to protect fall Chinook spawning nests. During fall Chinook operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet winter loads. The Fall Chinook Program spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C.J. Strike, Bliss, Upper and Lower Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, C.J. Strike, and Swan Falls projects.

Water-Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the hydroelectric production is needed are especially beneficial. Acquiring water through the Idaho Department of Water Resources' Water Supply Bank[22] also helps the company improve water-quality and temperature conditions in the Snake River

[22] idwr.idaho.gov/iwrb/programs/water-supply-bank/.

as part of ongoing relicensing efforts associated with the HCC. The company does not currently have any standing water lease agreements. However, single-year leases from the Upper Snake Basin are occasionally available, and the company plans to continue to evaluate potential water lease opportunities in the future.

Cloud Seeding

During the 2021 Idaho legislative session, HB 266, related to cloud seeding activities throughout the state, was passed. The legislation states that cloud seeding is in the public interest and that augmenting water supplies provides significant benefits in the areas of drought mitigation, water rights protection, municipal and business development, water quality, recreation, and fish and wildlife. The legislation instructs the IWRB to authorize cloud-seeding in basins throughout the state that experience depleted or insufficient water supplies. In addition, the legislation allows the IWRB to use state funds to support cloud seeding programs within the state where water supply is not sufficient. Following the enactment of the new legislation, all cloud-seeding programs in which Idaho Power is involved were granted authorization by the IWRB.

Cloud seeding ground generator.

Idaho Power has a long history of cloud-seeding beginning in 2003. The program originally increased snowpack in the south and middle forks of the Payette River watershed. The company then expanded this program to the Upper Snake River Basin above Milner Dam. Idaho Power has continued to collaborate with the IWRB and water users in the Upper Snake, Boise, and Wood River basins to expand the target area to include those watersheds.

Idaho Power seeds clouds by introducing silver iodide into winter storms. Cloud seeding increases precipitation from passing winter storm systems. If a storm has abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation. Idaho Power uses two methods to seed clouds:

1. Remotely operated ground generators releasing silver iodide at high elevations
2. Modified aircraft burning flares containing silver iodide

Benefits of either method vary by storm, and the combination of both methods provides the most flexibility to successfully introduce silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide particles and eventually grow and fall to the ground as snow downwind.

Silver iodide particles are very efficient ice nuclei, allowing minute quantities to have an appreciable increase in precipitation. It has been used as a seeding agent in numerous western states for decades.[23] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 22% annually, with an annual average of 11.5%. Idaho Power estimates cloud seeding, on average, provides an additional 633,000 acre-feet in the Upper Snake River, 112,000 acre-feet in the Wood River Basin, 273,000 acre-feet in the Boise Basin, and 223,000 acre-feet in the Payette River Basin, for a total average annual benefit of 1,240,000 acre-feet. At program build-out (including additional aircraft and remote ground generators), Idaho Power estimates additional runoff, on average, from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,650,000 acre-feet. The additional water from cloud seeding helps fuel the hydropower system along the Snake River.

The program Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment (SNOWIE) was a joint project between the National Science Foundation and Idaho Power. As part of the SNOWIE project, researchers from the universities of Wyoming, Colorado, and Illinois used Idaho Power's operational cloud seeding project, meteorological tools, and equipment to identify changes within wintertime precipitation after cloud seeding had taken place. Multiple scientific papers have already been published,[24] with more planned for submission about the effects and benefits of cloud seeding.

Idaho Power continues to collaborate with the State of Idaho and water users to augment water supplies with cloud seeding. The program in the central mountains (Payette, Boise, and Wood River basins) includes 32 remote-controlled, ground-based generators and two aircraft. The Upper Snake River Basin program includes 25 remote-controlled, ground-based generators and one aircraft operated by Idaho Power targeting the Upper Snake and Henry's Fork, as well as 25 manual, ground-based generators operated by a coalition of stakeholders in the Upper Snake.

[23] dri.edu/making-it-snow/.

[24] French, J. R., and Coauthors, 2018: Precipitation formation from orographic cloud seeding. Proc. Natl. Acad. Sci. USA, 115, 1168–1173, doi.org/10.1073/pnas.1716995115.

Tessendorf, S.A., and Coauthors, 2019: Transformational approach to winter orographic weather modification research: The SNOWIE Project. Bull. Amer. Meteor. Soc., 100, 71–92, journals.ametsoc.org/doi/full/10.1175/BAMS-D-17-0152.1.

Coal Facilities

Jim Bridger

Idaho Power owns one-third, or 707 MW[25] of net dependable capacity, of the Jim Bridger coal power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility. PacifiCorp and Idaho Power are in the process of converting units 1 and 2 from coal to gas by spring 2024. For additional details on the Jim Bridger plant, refer to Chapter 5—Future Supply-Side Generation and Storage Resources. For the 2023 IRP, Idaho Power used the AURORA model's capacity expansion capability to evaluate a range of exit dates and gas conversion possibilities for the company's participation in the Jim Bridger units 3 and 4.

North Valmy

Idaho Power and NV Energy are each 50% co-owners of the North Valmy coal power plant located near Winnemucca, Nevada. NV Energy is the operator of the North Valmy facility. Idaho Power's participation in the coal operations of North Valmy Unit 1 ceased at year-end 2019. Idaho Power currently participates 50%, or 134 MW of net dependable capacity, in the second generating unit at North Valmy.

In early 2023, NV Energy and Idaho Power began discussing a conversion of North Valmy units 1 and 2 to natural gas fired operation in 2026. As such, the 2023 IRP analysis encompasses the conversion of these two units with the details contained in Chapter 5—Future Supply-Side Generation and Storage Resources.

Natural Gas Facilities and Diesel Units

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 176-MW[26] Siemens–Westinghouse 501F natural gas simple-cycle combustion turbine (SCCT) located east of the Danskin plant in Mountain Home, Idaho.

Danskin

The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 163-MW[27] Siemens 501F and two 39-MW[27] Siemens–Westinghouse W251B12A SCCTs at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. After an upgrade anticipated for fall 2023, Danskin's larger unit will have an increased capacity of 176 MW[27].

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[25] MW nameplate = net dependable capacity.

[26] Generating capacity (MW) at ISO reference temperature of 59 degrees Fahrenheit. Unit by unit capacity varies with ambient conditions and is higher in the winter and lower at peak summer loads.

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, which uses a nominal 299-MW[27] natural gas combined-cycle combustion turbine (CCCT). The plant consists of one 186-MW[27] Siemens STG-5000F4 combustion turbine and one 93-MW[27] Siemens SST-700/SST-900 reheat steam turbine. The plant also has duct burners that provide an additional 20 MW[27] of achievable capacity. The Langley Gulch plant, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012.

Diesel

Idaho Power owns and operates two diesel generation units in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5.5 MW and are operated during emergency conditions, primarily for voltage and load support.

Battery Energy Storage Systems

Utility-scale Battery Energy Storage Systems (BESS) have come to hold a critical role for Idaho Power as the company continues to work to provide reliable and affordable energy in the face of rapidly growing demand for electricity. Utility-scale BESS will also assist in forging Idaho Power's path to reach its established goal to provide 100% clean energy by 2045.

Hemingway BESS

In summer 2023, an 80-MW BESS was installed at the company's Hemingway substation in Owyhee County. The company's BESS at Hemingway is designed to discharge stored energy at a maximum discharge rate of 80 MW, and has a total energy storage capacity of 320 MWh. In 2024, the company plans to install an additional 36-MW/144-MWh BESS. The total BESS capacity at Hemingway will be 116 MW/464 MWh.

Black Mesa BESS

A 40-MW/160-MWh BESS is being built adjacent to the 40-MW Black Mesa Solar facility in Elmore County and is expected to come online in September 2023.

Distribution-Connected Storage

Four different distribution-connected storage projects are scheduled to be online in fall 2023. The distribution-connected storage projects serve a dual purpose. In addition to providing the system with capacity, the project installations will assist in alleviating peak load as they are located in stations where transformer upgrades can be deferred. The four projects are located at the Filer, Weiser, Melba and Elmore substations for a combined capacity of 11 MW.

Franklin BESS

A 60-MW/240-MWh BESS is planned for installation adjacent to the upcoming 100-MW Franklin Solar facility in Twin Falls County. The BESS project is scheduled to come online in 2024.

Happy Valley BESS

A 77-MW/308-MWh MW BESS is planned for installation at the company's Happy Valley substation in Canyon County. The 77-MW BESS is scheduled to come online in 2025.

Customer Generation Service

Idaho Power's on-site generation services allow customers to generate power on their property and connect to Idaho Power's system. For participating customers, the energy generated is first consumed on the property itself, while excess energy flows on to the company's grid.

Most customer generators use solar PV systems. As of August 2023, there were 16,570 solar PV systems interconnected through the company's customer generation tariffs with a total capacity of 153.6 MW. At that time, the company had received completed applications for an additional 986 solar PV systems, representing an incremental capacity of 12.9 MW. For further details regarding customer-owned generation resources interconnected through the company's on-site generation and net metering services, see tables 4.3 and 4.4.

Table 4.3 Customer generation service customer count as of August 2023

Resource Type	Active	Active-Pending Expansion	Application Received	Grand Total
Idaho Total	**16,354**	**47**	**966**	**17,367**
Hydro	12			12
Other	3			3
Solar	16,312	47	966	17,325
Wind	27			27
Oregon Total	**216**		**20**	**236**
Solar	216		20	236
Grand Total	**16,570**	**47**	**986**	**17,603**

Table 4.4 Customer generation service generation capacity (MW) as of August 2023

Resource Type	Active	Active-Pending Expansion	Application Received[1]	Grand Total
Idaho	**150.4**	**0.3**	**12.7**	**163.4**
Hydro	0.2	0.0	0.0	0.2
Other	0.6	0.0	0.0	0.6
Solar	149.5	0.3	12.7	162.5
Wind	0.1	0.0	0.0	0.1
Oregon	**3.2**	**0.0**	**0.3**	**3.4**
Solar	3.2	0.0	0.3	3.4
Grand Total	**153.6**	**0.3**	**12.9**	**166.8**

[1]Total may not sum due to rounding.

Public Utility Regulatory Policies Act

As of January 1, 2023, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,211 MW of nameplate capacity. These PURPA contracts are for hydroelectric projects, cogeneration projects, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power generation facilities. Of the 133 contracts, 129 were online as of January 1, 2023, with a cumulative nameplate rating of approximately 1,136 MW. Figure 4.2 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

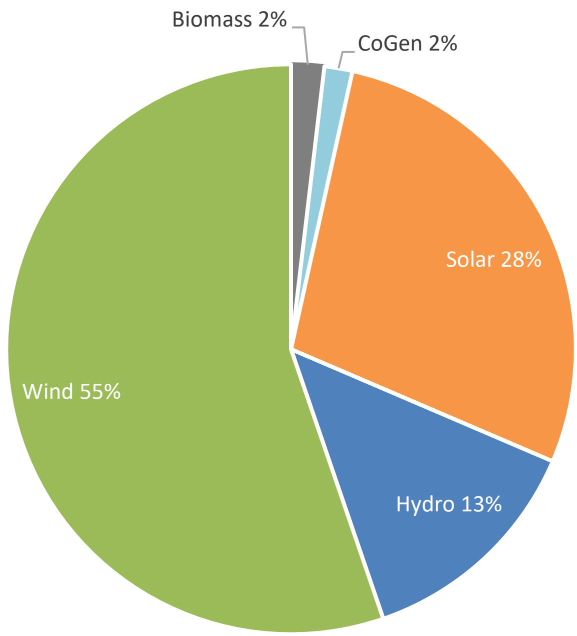


Figure 4.2 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. Details on signed PURPA contracts, including capacity and contractual delivery dates, are included in *Appendix C—Technical Report*.

Non-PURPA Power Purchase Agreements

Elkhorn Wind

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, for 101 MW of nameplate wind generation from the Elkhorn Wind Project located in northeastern Oregon. The Elkhorn Wind Project began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project. Idaho Power's contract with Telocaset Wind Power Partners expires December 2027.

Raft River Energy

In January 2008, the IPUC approved a PPA with Raft River Energy I, LLC, for approximately 13 MW of nameplate generation from the Raft River Geothermal Power Plant Unit 1 located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. Idaho Power is entitled to 51% of all RECs generated by the project for the remaining term of the agreement. Idaho Power's contract with Raft River Energy I expires in April 2033.

Neal Hot Springs

In May 2010, the IPUC approved a PPA with USG Oregon, LLC, for approximately 27 MW of nameplate generation from the Neal Hot Springs Unit 1 geothermal project located in eastern Oregon. The Neal Hot Springs Unit 1 project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project. Idaho Power's contract with USG Oregon expires in November 2037.

Jackpot Solar

In 2019, the IPUC approved a PPA with Jackpot Solar, LLC, for 120 MW of nameplate PV generation located north of the Idaho–Nevada state line near Rogerson, Idaho. Under the terms of the PPA, Idaho Power will receive all RECs from the project. Jackpot Solar began commercial operations in December 2022.

Black Mesa Solar

In 2022, the IPUC approved a PPA with Black Mesa Energy, LLC, for the 40 MW Black Mesa Solar facility, the output of which is dedicated for Micron's renewable energy use under the company's CEYW program. Black Mesa Solar began commercial operations on June 1, 2023, and is one of the first projects under Idaho Power's CEYW—Construction offering, enabling large customers to partner with Idaho Power on new, dedicated renewable energy resources to meet business sustainability goals. The RECs generated by the project will be retired on Micron's behalf.

Franklin Solar

In January 2023, Idaho Power and Franklin Solar, LLC entered into a PPA for a 100 MW solar project, Franklin Solar, to be located in Twin Falls County, Idaho. The Franklin Solar project is scheduled to come online in 2024.

Kuna Storage

In April 2023, Idaho Power and Cedar Holdco, LLC entered into an agreement under which Cedar Holdco, LLC will build, own, and maintain a 150-MW/600-MWh BESS facility in Kuna, Idaho. Under the agreement, the BESS facility will provide 150 MW of capacity on Idaho Power's system for 20 years, and Idaho Power will have the exclusive right to charge and discharge the project in exchange for a monthly payment. The Kuna BESS is scheduled to come online in 2025.

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie PUD in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 19.5 MW nameplate capacity power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally, primarily during months when Idaho Power expects to have surplus energy. The agreement extends through 2025. The Arrowrock project produces an average of 71,000 MWh annually.

Power Market Purchases and Sales

Idaho Power relies on regional power markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power leverages the regional power market to make purchases during peak-load periods. The existing transmission system is used to import these power purchases. Regional power markets benefit Idaho Power customers through decreased energy costs and increased reliability.

Transmission Import Rights

Idaho Power's interconnected transmission system facilitates market purchases to access resources to serve load. Five transmission paths connect Idaho Power to neighboring utilities:

1. Idaho–Northwest (Path 14)
2. Idaho–Nevada (Path 16)
3. Idaho–Montana (Path 18)
4. Idaho–Wyoming (Path 19)
5. Idaho–Utah (Path 20)

Idaho Power's interconnected transmission facilities were all jointly developed with other entities and act to meet the needs of the interconnecting participants. Idaho Power owns various amounts of capacity across each transmission path. The paths and their associated capacity are further described in Chapter 7—Transmission Planning. Idaho Power reserves portions of its transmission capacity to import energy for load service (network set-aside). Set-aside capacity, along with existing contractual obligations, consumes nearly all of Idaho Power's import capacity on all paths (see Table 7.1 in Chapter 7—Transmission Planning).

Idaho Power continually evaluates market opportunities to meet near-term needs. Idaho Power currently has long-term wholesale energy market purchases for summer peak hours through 2024 for 151 MW.

5. FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

Generation Resources

Hemingway Storage.

Supply-side resources include traditional generation, renewable, and storage resources. As discussed in Chapter 6, demand-side programs are an essential and valuable component of Idaho Power's resource strategy. The following sections describe the supply-side resources and energy-storage technologies considered when Idaho Power developed and analyzed the resource portfolios for the 2023 IRP. Not all supply-side resources described in this section were included in the modeling, but every resource described was considered.

The primary source of cost information for the 2023 IRP is the 2022 Annual Technology Baseline report released by the National Renewable Energy Laboratory.[27] Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the recency of the information. For a full list of the resources and cost information modeled in the 2023 IRP, refer to Chapter 8.

Resource Contribution to Peak

In the 2021 IRP, Idaho Power adopted the ELCC methodology, a reliability-based metric used to assess the capacity contribution of variable and energy-limited resources. The company has since expanded and refined this analysis for the 2023 IRP using Idaho Power's internally developed RCAT. [28] The ELCC of a resource is first determined by calculating the perfect generation unit size required to achieve a LOLE of 0.1 event-days per year. Then, the resource being evaluated is added to the system, and the new perfect generation unit size required is calculated. The ELCC of a given resource is equal to the difference in the size of the perfect generator units divided by the resource's nameplate.

To account for weather variations in the data, six different test years were used. The results from each of the test years were then averaged to produce a singular contribution to peak for

[27] atb.nrel.gov/.

[28] Billinton, R. and R. Allan, 'Power system reliability in perspective', *IEE J. Electronics Power.*

each specified variable and energy-limited resource. ELCC values for existing and future resources, as well as more information regarding the methodologies and calculations used for this analysis, can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

Renewable Resources

Renewable energy resources serve as the foundation of Idaho Power's existing portfolio. The company emphasizes a long and successful history of prudent renewable resource development and operation, particularly related to its fleet of hydroelectric generators. In the 2023 IRP, a variety of renewable resources were included in all of the portfolios analyzed. Renewable resources are discussed in general terms in the following sections.

Hydroelectric

Low-cost hydroelectric power is the foundation of Idaho Power's electrical generation fleet. Small-scale hydroelectric projects have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PPAs with Idaho Power. Because additional small-scale hydro resources are not expected to see significant further development, they have not been included as a selectable resource in the LTCE modeling.

Solar

The primary types of solar generation technology are utility-scale PV and distributed PV (primarily customer-owned). Solar PV converts sunlight directly into electrical energy. Direct current energy passes through an inverter, converting it to alternating current that can then be used on-site or sent to the grid.

For Idaho Power's cost estimates, operating parameters, and ELCC calculations for utility-scale PV resources, see the Supply-Side Resource and Loss of Load Expectation sections of *Appendix C—Technical Report*.

Targeted Grid Storage

Since the 2021 IRP, Idaho Power has moved forward with the installation of four distribution-connected storage projects with the intent to defer growth-driven transmission and distribution (T&D) system investments. These projects are shown in Table 5.1

Table 5.1 Targeted grid storage projects

Location	Season/Year	Capacity (MW)	Energy (MWh)	Estimated Deferral Years
Filer	Fall 2023	2	8	5
Weiser	Fall 2023	3	12	10
Melba	Fall 2023	2	8	4
Elmore	Fall 2023	4	16	9

It is anticipated that a locational value of T&D deferral, estimated at 10% of the utility-scale storage cost, may apply to an annual average of 5 MW of storage over the 20-year IRP forecast for a total potential of 100 MW of distribution-connected storage. This resource option was added to the AURORA LTCE model.

While solar can occasionally be used to offset T&D investment, the instances are infrequent. Batteries can provide T&D deferral value and are a cost-effective addition to the system as load continues to increase. Batteries are also more practical to defer T&D investment because the land requirement is lower than that of solar or solar plus battery installations.

Geothermal

The basic principle of geothermal generation is that it converts heat from the earth into electrical energy. Based on exploration to date in southern Idaho, geothermal development has potential in Idaho Power's service area; however, the potential for geothermal generation in southern Idaho remains somewhat uncertain. The time required to discover and prove geothermal resource sites is extensive; for this reason, Idaho Power has modeled the first selectable date for geothermal as 2030.

For Idaho Power's cost estimates and operating parameters for geothermal generation, see the Supply-Side Resource section of *Appendix C—Technical Report*.

Wind

Wind turbines collect and transfer energy from high wind areas into electricity. A typical wind development consists of numerous wind turbines, with each turbine ranging in size from 1 to 5 MW. Most potential wind sites in southern Idaho lie between the south-central and the southeastern part of the state.

Upon comparison with other renewable energy alternatives, wind energy resources are well suited for the Intermountain and Pacific Northwest regions, as demonstrated by the large number of existing projects.

For Idaho Power's cost estimates, operating parameters, and ELCC calculations for wind resources, see the Supply-Side Resource and Loss of Load Expectation sections of *Appendix C—Technical Report*.

Biomass

The 2023 IRP includes biomass generation as a resource option. There are currently small quantities of biomass in Idaho Power's service area, for example, multiple anaerobic digesters have been built in southern Idaho due to the size and proximity of the dairy industry and the large quantity of fuel available. Biomass in the 2023 IRP is modeled as fuel agnostic and not something specific like a horde of hamsters converting food waste pellets to mechanical energy using small flywheel cages.

For Idaho Power's cost estimates and operating parameters for a new biomass plant, see the Supply-Side Resource section of *Appendix C—Technical Report*.

Thermal Resources

Conventional thermal generation resources are essential to providing dispatchable capacity, which is critical in maintaining the reliability of a bulk-electrical power system and integrating renewable energy into the grid. Conventional thermal generation technologies include natural gas, hydrogen, nuclear, and coal resources.

Natural Gas Resources

Natural gas resources burn natural gas in a combustion turbine to generate electricity. CCCTs are commonly used for baseload energy, while faster ramping but less-efficient SCCTs are used to generate electricity during peak-load periods, or times of low variable resource output. Additional details related to the characteristics of both types of natural gas resources are presented in the following sections. CCCT and SCCT resources are typically sited near existing natural gas transmission pipelines. All of Idaho Power's existing natural gas generators are located adjacent to major natural gas pipelines. All new natural gas resources are hydrogen convertible.

Simple-Cycle Combustion Turbines

SCCT natural gas technology involves pressurizing air that is then heated by burning gas in fuel combustors. The hot, pressurized air expands through the blades of the turbine that connects by a shaft to the electric generator. Designs range from larger industrial machines at 80 to 200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are typically less economical on a per-MWh basis. However, SCCTs can respond more quickly to grid fluctuations.

SCCT generating resources remain a viable option to meet demand during critical periods. The SCCT plants may also be dispatched based on economics during times when regional energy prices peak due to weather, fuel supply shortages, or other external grid influences.

For Idaho Power's cost estimates and operating parameters for a SCCT unit, see the Supply-Side Resource section of *Appendix C—Technical Report*.

Combined-Cycle Combustion Turbines

CCCT technology benefits from a relatively low initial capital cost compared to other baseload resources; has high thermal efficiencies; is highly reliable; provides significant operating flexibility; and when compared to coal, emits fewer emissions and requires fewer pollution controls. Modern CCCT facilities are highly efficient and can achieve efficiencies of approximately 60% under ideal conditions.

A traditional CCCT plant consists of a natural gas turbine/generator equipped with a heat recovery steam generator to capture waste heat from the turbine exhaust. The heat recovery steam generator uses waste heat from the combustion turbine to drive a steam turbine generator to produce additional electricity. In a CCCT plant, heat that would otherwise be wasted to the atmosphere is reclaimed and used to produce additional power beyond that typically produced by an SCCT. New CCCT plants can be constructed, or existing SCCT plants can be converted to combined cycle units by adding a heat recovery steam turbine/generator.

For Idaho Power's cost estimates and operating parameters for a CCCT resource, see the Supply-Side Resource section of *Appendix C—Technical Report*.

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engine generation sets are typically multi-fuel engines connected to a generator through a flywheel and coupling. They are typically capable of burning natural gas or other liquid petroleum products. They are mounted on a common base frame, resulting in the ability for an entire unit to be assembled, tuned, and tested in the factory prior to delivery to the power plant location. This production efficiency minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple identical units, allowing each engine to be operated at its highest efficiency level once started. As demand for grid generation increases, additional units can be started sequentially or simultaneously. This configuration also allows for relatively inexpensive future expansion of the plant capacity. Reciprocating engines provide unique benefits to the electrical grid. They are extremely flexible because they can provide ancillary services to the grid in just a few minutes. Engines can go from a cold start to full load in 10 minutes. Given the large overlap of capabilities with SCCTs, reciprocating engines were considered for, but not part of, the LTCE modeling in the 2023 IRP.

Combined Heat and Power

Combined heat and power (CHP), or cogeneration, typically refers to simultaneous production of both electricity and useful heat from a single plant. CHP plants are typically located at, or near, commercial or industrial facilities capable of using the heat generated in the process. These facilities are sometimes referred to as the steam host. Generation technologies frequently used in CHP projects are gas turbines or reciprocating engines with a heat-recovery unit.

The main advantage of CHP is the higher overall efficiencies that can be obtained because the steam host can use a large portion of the waste heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, investment in additional transmission capacity can also often be avoided.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different. While not expressly analyzed in the 2023 IRP, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company.

Coal Conversion to Natural Gas

There are two primary methods to convert an existing coal power plant to natural gas. The first, less-common method is to fully retire the existing coal facility and replace it with either a CCCT or SCCT natural gas facility. This method removes the existing coal boiler, turbine, generator, and all coal support equipment, but uses the already existing transmission and interconnection infrastructure. The second, more-common method is to convert the existing steam boiler to use natural gas instead of coal.[29] In either case, the conversion process can create numerous benefits, including reduced emissions, reduced plant Operations and Maintenance (O&M) expenses, reduced capital costs, and increased flexibility. For purposes of the 2023 IRP, Idaho Power has modeled only the second method in which a specific coal facility's existing steam boiler is converted to use natural gas instead of coal.

Jim Bridger Coal to Natural Gas Conversion

Jim Bridger units 1 and 2 will be converted to natural gas in 2024, as determined in the 2021 IRP. Units 3 and 4 continue to operate on coal with the currently installed Selective Catalytic Reduction (SCR).

For the 2023 IRP, Idaho Power used AURORA's LTCE model to determine the best Bridger operating option specific to Idaho Power's system, subject to the following constraints:

- Units 1 and 2—Convert to natural gas in 2024 and operate through 2037
- Unit 3—

[29] eia.gov/todayinenergy/detail.php?id=44636.

  - Operate on coal through 2029, convert to natural gas in 2030, and operate through 2037
  - Do not convert to natural gas and exit the unit at the end of 2029, or no earlier than the end of 2025
- Unit 4—
  - Operate on coal through 2029, convert to natural gas in 2030, and operate through 2037
  - Do not convert to natural gas and exit the unit at the end of 2029, or no earlier than the end of 2025

Costs associated with continued capital investments and early exit or conversion were included in the analysis. If the units were converted to natural gas, changes to the fuel costs and operating expenses were modeled to accurately capture the change in fuel. For those scenarios where units 3 and 4 convert to natural gas, they are assumed to operate through their useful life and are exited in 2037.

The Jim Bridger units provide system reliability benefits, particularly related to the company's flexible ramping capacity needs for EIM participation and reliable system operations. The need for flexible ramping is simulated in the AURORA modeling.

North Valmy Coal to Natural Gas Conversion

As co-owners of the North Valmy Generating Station, NV Energy and Idaho Power aligned on 2026 as the year to evaluate the coal to gas conversion for units 1 and 2.

For the 2023 IRP, Idaho Power used AURORA's LTCE model to determine the best North Valmy operating option specific to the company's system, subject to the following constraints:

- Allow for the exit of Unit 2 at the end of 2025 or the conversion to natural gas with SCR in 2026.
- If the conversion of Unit 2 to natural gas is selected, then the conversion of Unit 1 with SCR becomes available to the model and it can either select to remain out of Unit 1 or to convert it to natural gas operation.

In the event that the model selects any conversion to natural gas option, the company also evaluated early retirement dates.

Green Hydrogen

Green hydrogen is created from renewable electricity and water by electrolysis and has no carbon emissions.

Since the 2021 IRP, Idaho Power has continued to monitor hydrogen-based generation and believes technological progress warrants its inclusion in the 2023 IRP. Based on technology-specific research and studies, as well as input from IRPAC, the company allowed the model to select hydrogen generation beginning in 2037. While Idaho Power does not know which hydrogen technology may become commercially dominant, the company needed to select a technology profile to model within AURORA and, informed by available technology research, chose to model hydrogen as a SCCT with similar operating characteristics to natural gas units except for the fuel they burn and the emissions they produce. To be clear, Idaho Power modeled hydrogen as a resource with no carbon emissions.

The 2023 IRP is the first resource plan in which hydrogen-specific resources have been modeled; the company anticipates additional advancements associated with hydrogen and, as such, expects that ultimate development of the technology may differ from the current modeling approach. Idaho Power will continue to monitor advancements in hydrogen resources and refine its modeling assumptions in future long-term plans.

Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for many years, and Idaho Power continues to evaluate various nuclear technologies in the IRP process. Considering the location of the INL within Idaho Power's service area in eastern Idaho, the company's long-term planning has typically assumed that an advanced-design small modular reactor (SMR) could be built on the INL site.

For the 2023 IRP, a 100 MW SMR was modeled as a selectable resource beginning in 2030—a timeline the company considered reasonable given the current state of the technology and the federal regulatory approval process. Compared to typical reactor designs, SMRs offer potential benefits, including smaller physical footprints, reduced capital investment, plant size scalability, and greatly enhanced flexibility. Although current operating parameters are not available, Idaho Power has modeled the operational characteristics of an SMR plant similar to a combined cycle plant. Grid services provided by the SMR include baseload energy, peaking capacity, and flexible capacity.

For Idaho Power's cost estimates and operating parameters for an advanced SMR nuclear resource, see the Supply-Side Resource section of *Appendix C—Technical Report*.

Coal Resources

Conventional coal generation resources have been part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over emissions and climate change coupled with regulatory uncertainty have made it imprudent to consider building new conventional coal generation resources. No new coal-based energy resources were modeled as part of the 2023 IRP.

Storage Resources

As increasing amounts of VERs are built within the region, the value of energy storage increases. There are many energy storage technologies at various stages of development, such as battery storage, hydrogen storage, compressed air, flywheels, pumped hydro storage, iron-air storage, and others. The 2023 IRP considered a variety of energy-storage technologies and modeled battery storage based on lithium ion (Li-ion) technology, longer-duration battery storage based on iron-air technology, and pumped hydro storage.

Energy storage can provide numerous grid services in various durations. Short-term services include ancillary services like frequency regulation, spinning reserve, and reactive power support. In the medium duration, storage today can provide peak shaving, arbitrage, T&D deferral, and firming for VERs. Long duration storage can shift energy between seasons.

Battery Storage

There are many types of battery-storage technologies at various stages of development. The dominant chemistry used in the market today is Li-ion, which provides significant advantages over other commercially available battery-storage technologies. Those advantages include high cycle efficiency, high cycle life, fast response times, and high energy density. Idaho Power modeled Li-ion storage over other technologies in the 2023 IRP for short and medium duration storage. Idaho Power will continue to observe and evaluate the changing storage technology landscape.

Prior to the passage of the IRA, storage resources were typically paired with solar facilities to maximize tax credits that would otherwise not be available to standalone storage facilities. Post-passage of the IRA, ITCs are available to standalone storage facilities. As a result, the 2023 IRP modeled standalone storage facilities only. This option creates more flexibility for storage selection within the model, as AURORA will make cost-effective selections for storage that may (or may not) be paired with solar or other resources based on need and cost-effectiveness.

For Idaho Power’s cost estimates, operating parameters, and ELCC calculations, see the Supply-Side Resource and Loss of Load Expectation sections of *Appendix C—Technical Report*.

Pumped Hydro Storage

Pumped hydro storage is a type of hydroelectric power that stores potential energy by pumping water from a lower to a higher elevation. Energy is generated when the water flows from the higher reservoir like a normal hydroelectric facility.

Pumped hydro storage projects are often large and become more feasible when large amounts of storage are identified as a system need.

For Idaho Power's cost estimates and operating parameters for pumped-hydro storage, see the Supply-Side Resource section of the *Appendix C—Technical Report*.

Multi-Day Storage

Idaho Power added a new storage technology in the 2023 IRP: multi-day duration, 100-hour storage, in the form of iron-air batteries. Generally, these resources charge during periods of low demand and high renewable output in the spring and fall and discharge during periods of high demand in the summer and winter. The downside of this storage technology compared to other storage options is lower round-trip efficiency, which is expected to be less than half that of Li-ion batteries. Given these operating characteristics, this technology is best suited for inter-seasonal demand shaping and absorbing VER overproduction when they might otherwise be curtailed. As a technology that could serve a critical future need, Idaho Power will continue to monitor and model long-duration storage.

For Idaho Power's cost estimates and operating parameters for multi-day duration 100-hour storage, see the Supply-Side Resource section of the *Appendix C—Technical Report*.

6. DEMAND-SIDE RESOURCES

Demand-Side Management Program Overview

Idaho Power's Irrigation Peak Rewards program helps offset energy use on high-use days.

DSM resources offset future energy loads by reducing energy demand through either efficient equipment upgrades (energy efficiency) or peak-system demand reduction (demand response). Energy efficiency has been a critical resource in IRPs since 2004, providing average cumulative system load reductions of over 324 aMW by year-end 2022 while demand response programs provided 312 MW of available capacity to reduce system demand in 2022. Energy efficiency potential resources are screened for cost-effectiveness, then all achievable cost-effective energy efficiency potential resources are included in the IRP as a decrement to the load forecast before considering new supply-side resources. In addition, all achievable energy efficiency potential resources that were determined to not meet cost effective thresholds were grouped (bundled) according to price and season. These bundles were made available for selection by the AURORA model.

Accumulated energy efficiency is estimated to reduce energy demand at the time of the system peak by 360 MW. Also included in the Preferred Portfolio is 320 MW of nameplate summer peak demand reduction from existing demand response plus an additional 160 MW of demand response by the end of the planning timeframe.

Energy Efficiency Forecasting—Energy Efficiency Potential Assessment

For the 2023 IRP, Idaho Power's third-party contractor, Applied Energy Group (AEG), provided a 20-year forecast of Idaho Power's energy efficiency potential from a utility cost test (UCT) perspective. The contractor also provided additional bundles of energy efficiency and their associated costs beyond the achievable economic potential for analysis in the 2023 IRP.

For the initial study, the contractor developed three levels of energy efficiency potential: technical, economic, and achievable. The three levels of potential are described below.

1. *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. In new construction, customers and developers are assumed to

choose the most efficient equipment available. Technical potential also assumes the adoption of every applicable measure available. The retrofit measures are phased in over several years.

2. *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the energy efficiency potential study, the contractor applied the UCT for cost-effectiveness, which compares lifetime energy and capacity benefits to the cost of the program. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and adopt every cost-effective and applicable measure.
3. *Achievable*—Achievable potential considers market adoption, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential estimates a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market-adoption factors to the cost-effective potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The load forecast entered into AURORA includes the reduction to customer sales of all future achievable economic energy efficiency potential. Treatment of energy efficiency that could contribute beyond the decrement to the load forecast is discussed below.

Energy Efficiency Modeling

In addition to the baseline energy efficiency potential study that assessed technical, economic, and achievable potential in a manner consistent with past IRPs, the company modeled additional bundles of technically achievable energy efficiency and their costs in the AURORA model in the 2023 IRP.

Technically Achievable Supply Curve Bundling

In collaboration with AEG, an approach was established to allow technically achievable energy efficiency potential beyond the achievable economic potential, to be input into the AURORA model for possible selection. These bundles include measures that did not pass economic screening given current economic parameters but were made available for selection depending on various scenarios determined by the model. Technically achievable potential differs from the broader technical potential category, as AEG applies a market adoption factor intended to estimate those customers likely to participate in programs incentivizing more efficient processes or equipment, similar to the approach used when forecasting achievable potential.

Five bundles of energy efficiency measures were created that were grouped by summer or winter measures, and summer was spilt into a low, mid, and high-cost; and winter was split into low and high-cost bundles. Whether a measure belonged in the summer or winter groups depended on the ratio of peak winter to summer capacity determined by the measure's load shapes at the hour of seasonal peak need. The bundles were sized to be large enough for AURORA to recognize them as operationally viable resources, but small enough to keep the average levelized cost reflective of the costs of the associated measures.

The bundles were then loaded into the AURORA software with a 'nameplate' capacity (peak kW), levelized cost, and an 8,760-hour load shape that contained the percentage of peak demand for each hour of the year. Table 6.1 lists the average annual resource potential and average levelized cost for the bundles.

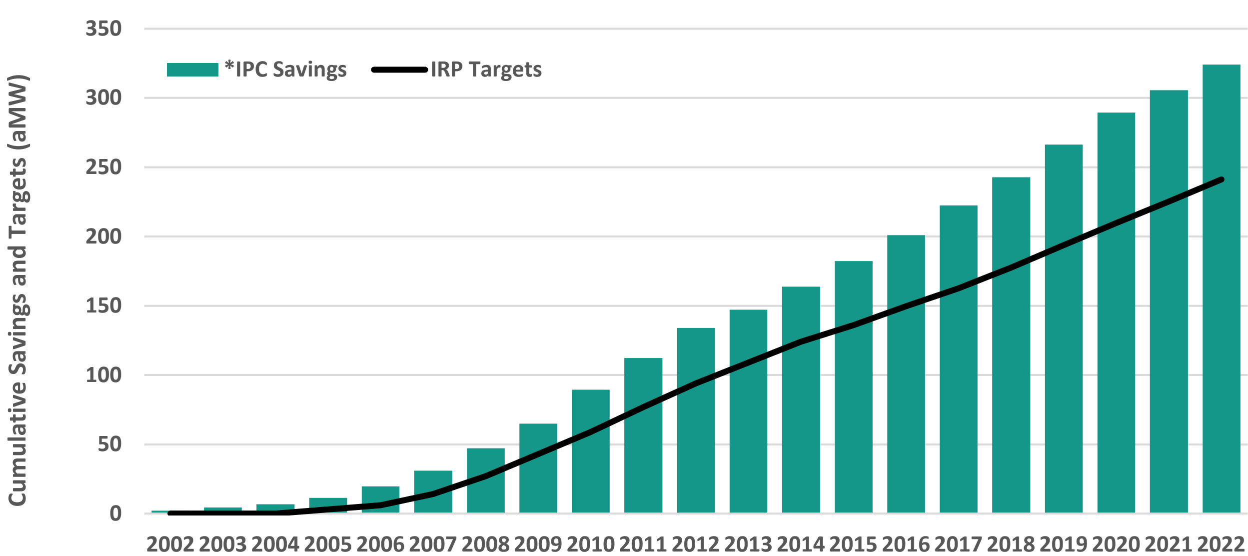
Table 6.1 Energy efficiency bundles average annual resource potential and average levelized cost

Bundle	20-Year Average Annual Potential (aMW)	20-Year Average Real Cost ($/MWh)
Summer Low-Cost	8.4	$96
Summer Mid-Cost	5.3	$297
Summer High-Cost	34.2	$663
Winter Low-Cost	10.5	$68
Winter High-Cost	10.3	$371

DSM Program Performance and Reliability

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative annual reduction of 324 aMW in 2022. Figure 6.1 shows the cumulative annual growth in energy efficiency savings from 2002 through 2022, along with the associated IRP targets developed as part of the IRP process since 2004.



*IPC Savings include Northwest Energy Efficiency Alliance non-code/federal standards savings

Figure 6.1 Cumulative annual growth in energy efficiency compared with IRP targets

Idaho Power's energy efficiency portfolio is currently a cost-effective resource. Table 6.2 shows the 2022 year-end program results, expenses, and corresponding benefit-cost ratios.

Table 6.2 Total energy efficiency portfolio cost-effectiveness summary, 2022 program performance

Customer Class	2022 Savings (MWh)	UCT ($000s)	Total Utility Benefits ($000s) (NPV*)	UCT: Benefit/ Cost Ratio	UCT Levelized Costs (cents/kWh)
Residential	28,525	$5,455	$4,585	0.8	4.3
Industrial/commercial	109,960	$17,940	$48,619	2.7	1.8
Irrigation	6,955	$2,080	$5,602	2.7	2.6
Total**	**145,440**	**$30,321**	**$58,806**	**1.9**	**2.1**

* NPV=Net Present Value

** Total UCT dollars, benefit/cost ratio and levelized costs include indirect program expenses included in the portfolio level but not in the customer class level

Note: Values may not add to 100% due to rounding. Excludes market transformation program savings

Energy Efficiency Performance

The company works with third-party contractors to conduct energy-efficiency program impact evaluations to verify energy savings and process evaluations to assess operational efficiency on a scheduled and as-required basis.

Idaho Power uses industry-standard protocols for its internal and external evaluation efforts, including the National Action Plan for Energy Efficiency—Model Energy Efficiency Program Impact Evaluation Guide, the California Evaluation Framework, the International Performance Measurement and Verification Protocol, the Database for Energy Efficiency Resources, and the Regional Technical Forum's evaluation protocols.

The timing of impact evaluations is based on protocols from these industry standards, with large-portfolio contributors being evaluated more often and with more rigor. Smaller portfolio contributors are evaluated less often and require less analysis as most of the program measure savings are deemed savings from the Regional Technical Forum or other sources. Evaluated savings are expressed through a realization rate (reported savings divided by evaluated savings). Realized savings of programs evaluated over the past four years (2019–2022) ranged between 44 and 110%. The realized weighted savings average over the same period is 100%.

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three programs. Table 6.3 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction and during the 2022 summer season, this program contributed 82% of the total potential demand-reduction capacity, or 255 MW. More details on

Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2022 Annual Report*.

Table 6.3 2022 demand response program capacity

Program	Customer Class	Reduction Technology	2022 Total Demand Response Capacity (MW)	Percent of Total 2022 Capacity*
A/C Cool Credit	Residential	Central A/C	26.8	9%
Flex Peak Programs	Commercial/Industrial	Various	30	10%
Irrigation Peak Rewards	Irrigation	Pumps	255.6	82%
Total			**312.4**	**100%**

* Values may not add to 100% due to rounding

Figure 6.2 shows the historical annual demand response program capacity between 2004 and 2022. The demand-response capacity was lower in 2013 because of the one-year suspension of both the irrigation and residential programs. The temporary program suspension was due to a lack of near-term capacity deficits being identified in the 2013 IRP.

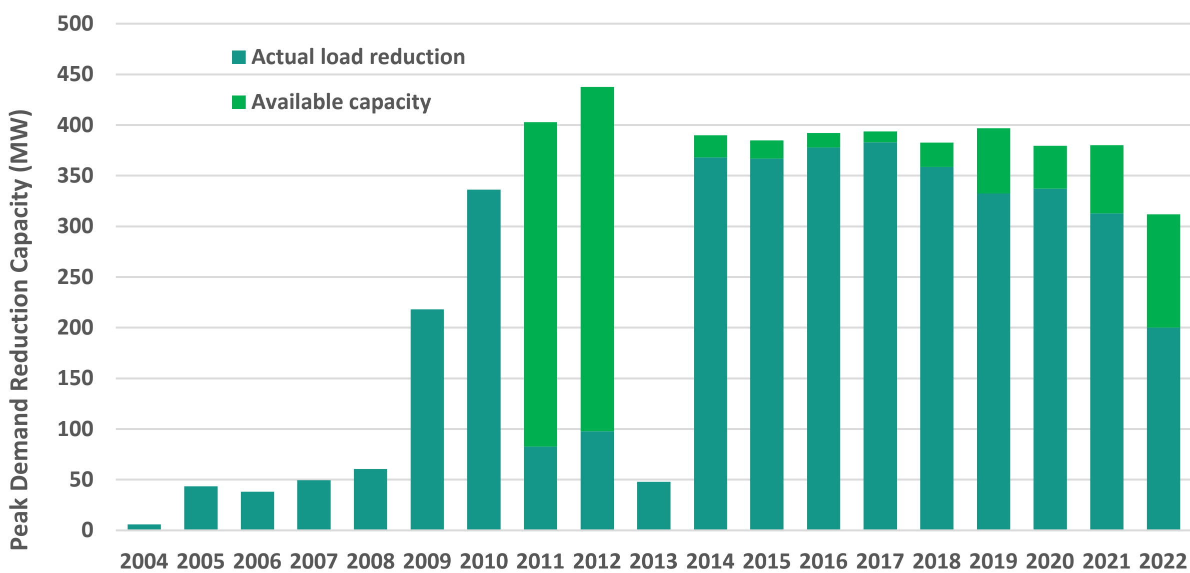


Figure 6.2 Historic annual demand response program performance

Demand Response Resource Potential

In the 2023 IRP, demand response from all existing programs was committed to provide 320 MW of peak capacity during June and July throughout the IRP planning period, with a reduced amount of program potential available during August and September. Because the total potential from demand response is dependent on anticipated load from program participants, the reduced amount of potential available during August and September is a result of irrigation load reducing over the demand response program season.

As part of the 2023 IRP's examination of the potential for expanded demand response, Idaho Power contracted with AEG to provide a 20-year forecast of Idaho Power's demand response program potential to estimate what may be available in Idaho Power's service area. Based on this study, Idaho Power grouped expansion of its current programs and other potential programs into similar price and characteristic buckets for analysis within the AURORA model.

The DR potential study also included a potential associated with pricing programs, notably time-of-use (TOU) and to a lesser degree, critical peak pricing (CPP). The company has existing TOU offerings in both Idaho and Oregon. The company's Idaho offering was initially developed in 2005, and now has approximately 1,000 customers enrolled. The company implemented TOU in Oregon in 2018 and has less than five customers enrolled. In Order No. 21-184, the OPUC requested the company report on the number of participants, the total cost of the program to date, and the peak capacity reduction by season. With the level of customer participation data in the Oregon TOU rate, the sample used to develop a comprehensive and reliable assessment of residential peak shifting would be outside an acceptable margin of error tolerance limit at approximately +/- 60%. As such, circumstantial behavioral changes could misrepresent peak shifting impacts when expanded to the full residential customer class. To date, the costs of administering the program have been limited to initial marketing efforts and are not materially significant. Finally, the OPUC requested that the company propose a venue to report TOU performance. The company suggests reporting ongoing TOU pilot performance and any changes to the offering in its annual distribution system planning (DSP) report, beginning with the summer 2022 report.

DR was evaluated in the 2023 IRP modeling process by using 180 MW of new DR potential identified from the 2022 DR potential study. The additional DR capacity was bucketed by like characteristics and price, then made available for selection in AURORA. This additional DR potential was represented by three separate buckets: 100 MW of existing program expansion, 60 MW of storage programs (for example, water heater or customer battery programs), and 20 MW associated with pricing programs. DR was available for selection in the AURORA model in 20 MW amounts, selectable each year, when analyzing the future load and resource buildout. Idaho Power will continue to evaluate DR expansion in its service area with each IRP planning cycle.

T&D Deferral Benefits

Energy Efficiency

For the 2023 IRP, Idaho Power determined the T&D deferral benefits associated with energy efficiency by performing an analysis to determine how effective energy efficiency is at deferring transmission, substation, and distribution projects. To perform the analysis, the company used historical and projected investments over a 20-year period from 2007 to 2026. Transmission, substation, and distribution projects at various locations across the company's system were represented. The limiting capacity (determined by distribution circuit, transformer, or transmission line) was identified for each project, along with the anticipated in-service date, projected cost, peak load, and projected growth rate.

Energy efficiency measures were assumed to have a lifespan equaling the average of existing measures—12 years. The cumulative energy efficiency from all cost-effective measures was included in the analysis.

Varying amounts of incremental energy efficiency were used and spread evenly across customer classes on all distribution circuits, based on the energy efficiency forecast. Peak demand reduction was calculated and applied to summer and winter peaks for the distribution circuits and substation transformers. If the adjusted forecast was below the limiting capacity, it was assumed an associated project—the distribution circuit, substation transformer, or transmission line—could be deferred. The financial savings of deferring the project were then calculated.

The total savings from all deferrable projects were divided by the total annual energy efficiency reduction required to obtain the deferral savings over the service area.

Idaho Power calculated the corresponding T&D deferral value as an average of the 20-year forecast of achievable energy efficiency. The 20-year average was $8.33 per kW-year. This value was then used in the calculation of energy efficiency cost-effectiveness in the 2022 energy efficiency potential study.

Distribution System Planning

In March 2019, the OPUC initiated an investigation into DSP in docket UM 2005 with the stated objective of directing electric utilities to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[30]

Over nearly two years, OPUC staff, stakeholders, and utilities have engaged in workshops and seminars to discuss DSP possibilities, best practices, and lessons learned from other jurisdictions. These efforts culminated in DSP guidelines from OPUC staff, which were subsequently adopted by the OPUC in Order 20-485 on December 23, 2020. The adopted DSP guidelines identify specific efforts that utilities must conduct, analyze, and compile into reports filed every two years. The initial report was split into two parts.[31] Within these reports,

[30] See OPUC UM 2005, Order No. 19-104.

[31] idahopower.com/energy-environment/energy/planning-and-electrical-projects/oregon-distribution-system-plan/.

the company identified how the DSP and resource planning processes can inform or impact each respective plan.

One of the clear relationships between DSP and integrated resource planning is the ability to consider avoided or deferred distribution investments as a cost offset to potential resource investments. The value of such T&D deferral will be evaluated closely in the DSP process, as well as in the company's IRP. DSP affects the calculation of the T&D deferral value included in the IRP's energy efficiency cost-effectiveness test and the T&D deferral value of distribution-connected resources in the IRP resource stack. To the extent IRP's resources impact the distribution system, local load forecasts and the distribution plan would be adjusted based on the anticipated resources.

There are differences between the IRP and DSP processes. The IRP analyzes several long-term peak forecast scenarios focused on long-term resource needs. The DSP, on the other hand, analyzes near-term loading scenarios that can stress the local area capacity or operating constraints that may occur at peak or light loads. Further, most resources identified in the IRP do not specify location. The DSP is needed to inform the locational value (or cost) of distribution-connected resources on Idaho Power's system.

7. TRANSMISSION PLANNING

Past and Present Transmission

500-kilovolt (kV) transmission line near Melba, Idaho.

High-voltage transmission lines are vital to the development of energy resources for Idaho Power customers. Transmission lines made it possible to develop a network of hydroelectric projects in the Snake River system, supplying reliable, low-cost energy. In the 1950s and 1960s, regional transmission lines stretching from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects. In the 1970s and 1980s, transmission lines allowed partnerships in three power plants in neighboring states to deliver energy to Idaho Power customers. Today, transmission lines connect Idaho Power to wholesale energy markets and help economically and reliably mitigate the variability of VERs. They also allow Idaho Power to import clean energy from other regions and are consequently critical to Idaho Power achieving its goal to provide 100% clean energy by 2045.

Idaho Power's transmission interconnections provide economic benefits and improve reliability by transferring electricity between utilities to serve load and share operating reserves. Historically, Idaho Power experiences its peak load at different times of the year than most Pacific Northwest utilities; as a result, Idaho Power can purchase energy from the Mid-C energy trading market during its peak load and sell excess energy to Pacific Northwest utilities during their peak. Additional regional transmission connections to the Pacific Northwest would benefit Idaho Power customers in the following ways:

- Delay or avoid construction of additional resources to serve peak demand
- Increase revenue from off-system sales during the winter and spring, which would then be credited to customers through the Power Cost Adjustment (PCA)
- Increase revenue from sales of transmission system capacity, which would then be credited to Idaho Power customers
- Increase system reliability
- Increase the ability to integrate VERs, such as wind and solar

- Improve the ability to implement advanced market tools more efficiently, such as the EIM

Transmission Planning Process

FERC mandates several aspects of the transmission planning process. FERC Order No. 1000 requires Idaho Power to participate in transmission planning on a local, regional, and interregional basis, as described in Attachment K of the Idaho Power Open-Access Transmission Tariff and summarized in the following sections.

Local Transmission Planning

Idaho Power uses a biennial process to create a local transmission plan identifying needed transmission system additions. The local transmission plan is a 20-year plan that incorporates planned supply-side resources identified in the IRP process, transmission upgrades identified in the local-area transmission advisory process, forecasted network customer load (e.g., Bonneville Power Administration [BPA] customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and third-party transmission customer requirements. By evaluating these inputs, required transmission system enhancements are identified that will ensure safety and reliability. The local transmission plan is shared with the regional transmission planning process.

A local-area transmission advisory process is performed every 10 years for each of the load centers identified, using unique community advisory committees to develop local-area plans. The community advisory committees include jurisdictional planners, mayors, city council members, county commissioners, representatives from large industry, commercial, residential, and environmental groups. Plans identify transmission and substation infrastructure needed for full development of the local area, accounting for land-use limits, with estimated in service dates for projects. Local-area plans are created for the following load centers:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Eastern Treasure Valley
5. Western Treasure Valley (this load-area includes eastern Oregon)
6. West Central Mountains

Regional Transmission Planning

Idaho Power is active in NorthernGrid, a regional transmission planning association of 13 member utilities. The NorthernGrid was formed in early 2020. Previously, dating back to 2007, Idaho Power was a member of the Northern Tier Transmission Group.

NorthernGrid membership includes Avista, Berkshire Hathaway Energy U.S. Transmission, BPA, Chelan County PUD, Idaho Power, NV Energy, NorthWestern Energy, PacifiCorp (Rocky Mountain Power and Pacific Power), Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. Biennially, NorthernGrid will develop a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, local transmission plans, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers. The 2020–2021 regional transmission plan was published in December 2021 and can be found on the NorthernGrid website: northerngrid.net. That plan identifies B2H and Gateway West (segments across southern Idaho as needed regional transmission additions. Similarly, the draft 2022–2023 regional transmission plan concludes that B2H and Gateway West segments continue to be needed by the region.

Existing Transmission System

Idaho Power's transmission system extends from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. Sets of lines that transmit power from one geographic area to another are known as transmission paths. Transmission paths are evaluated by the Western Electricity Coordinating Council (WECC) utilities to obtain an approved power transfer rating. Idaho Power has defined transmission paths to all neighboring states and between specific southern Idaho load centers as shown in Figure 7.1.

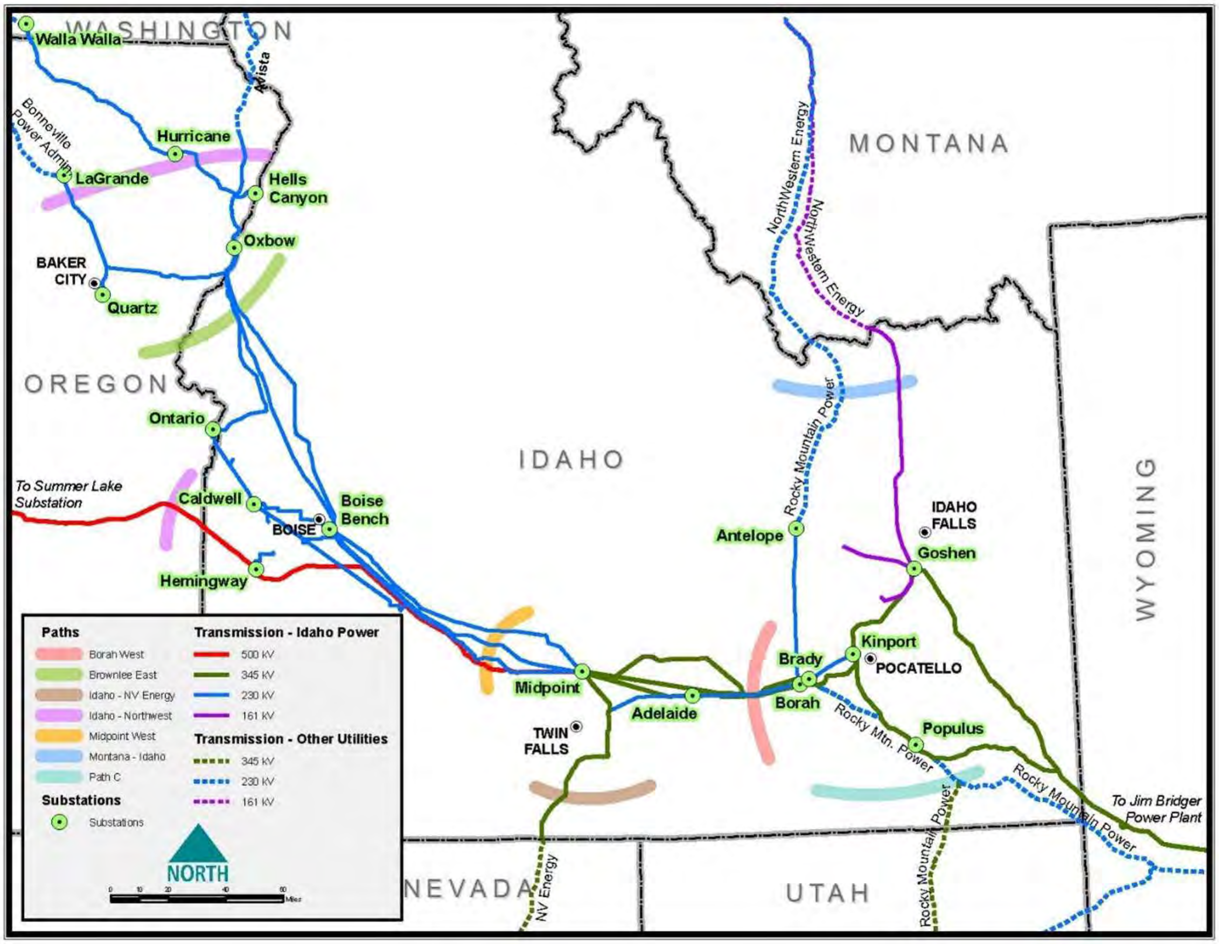


Figure 7.1 Idaho Power transmission system map

The transmission paths identified on the map are described in the following sections, along with the conditions that result in capacity limitations.

Idaho to Northwest Path

The Idaho to Northwest transmission path (WECC Path 14) consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney substation near Burns, Oregon. The Idaho to Northwest path is capacity-limited during summer months due to energy imports from the Pacific Northwest to serve Idaho Power retail load and transmission-wheeling obligations for the BPA load in eastern Oregon and southern Idaho. Additional transmission capacity is required to facilitate incremental market purchases from northwest entities to serve Idaho Power's growing customer base.

Operationally since 2020, Idaho Power has seen increased third-party demand for west-to-east or north-to-south firm transmission from the Pacific Northwest to the Desert Southwest or California.

Brownlee East Path

The Brownlee East transmission path (WECC Path 55) is on the east side of the Idaho to Northwest path shown in Figure 7.1. Brownlee East comprises the 230-kV and 138-kV lines east of the HCC and Quartz substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Total Brownlee East path (WECC Path 82).

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can transfer from the HCC, as well as energy imports from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

Idaho–Montana Path

The Idaho–Montana transmission path (officially Montana–Idaho WECC Path 18) consists of the Brady–Mill Creek 230-kV and Big Grassy–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy north-to-south from Montana into Idaho. In the north-to-south direction, Idaho Power has 167 MW of capacity on the path.

Borah West Path

The Borah West transmission path (WECC Path 17) is internal to Idaho Power's system and is jointly owned between Idaho Power and PacifiCorp. In the predominate east-to-west direction, Idaho Power owns 1,467 MW of the path, and PacifiCorp owns 1,090 MW of the path. The path includes 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation located near American Falls, Idaho. Idaho Power's one-third share of energy from the Jim Bridger plant flows over this path, as well as energy from east-side resources and imports from Montana, Wyoming, and Utah. Heavy path flows are likely to exist during low hydro operating conditions when power from the south is flowing to Idaho and the Pacific Northwest. This can occur daily, during peak solar production, or seasonally, when southern and eastern thermal and wind production moves west across the system to the Pacific Northwest. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Borah West path.

Midpoint West Path

The Midpoint West transmission path is internal to Idaho Power's system and is a jointly owned path between Idaho Power and PacifiCorp. In the predominate east-to-west direction, Idaho Power owns 1,710 MW of the path while PacifiCorp owns 1,090 MW of the path. The path is composed of 500-kV, 230-kV, and 138-kV transmission lines west of Midpoint substation located near Jerome, Idaho. The heaviest east-to-west path flows on Midpoint West are likely to correlate with Borah West. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

Idaho–Nevada Path

The Idaho–Nevada transmission path (officially Idaho–Sierra WECC Path 16) is the 345-kV Rogerson–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the North Valmy Power Plant was built in northern Nevada. Idaho Power is allocated 100% of the northbound capacity, while NV Energy is allocated 100% of the southbound capacity. The import, or northbound, capacity on the transmission path is 360 MW, of which Valmy Unit 2 uses approximately 130 MW.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West (WECC Path 19), is made up of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns 800 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east-to-west from Jim Bridger; consequently, the import capability of the Bridger West path into the Idaho Power area can be limited by Borah West path capacity constraints.

Idaho–Utah Path

The Idaho–Utah path, referred to as Path C (WECC Path 20), comprises 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path owner and operator of all the transmission lines. The path effectively feeds into Idaho Power's Borah West path when power is moving from south to north; consequently, the import capability of Path C into the Idaho Power area can be limited by Borah West path capacity constraints.

Table 7.1 summarizes the import capability for paths impacting Idaho Power operations and lists their total capacity and available transfer capacity (ATC); most of the paths are completely allocated with no capacity remaining.

Table 7.1 Transmission import capacity

Transmission Path	Import Direction	Capacity (MW)	ATC (MW)*
Idaho to Northwest	West-to-east	1,200–1,340	Varies by Month
Idaho–Nevada	South-to-north	360	Varies by Month
Idaho–Montana	North-to-south	383	Varies by Month
Brownlee East	West-to-east	1,915	Internal Path
Midpoint West	East-to-west	2,800	Internal Path
Borah West	East-to-west	2,557	Internal Path
Idaho–Wyoming (Bridger West)	East-to-west	2,400	86 (Idaho Power Share)
Idaho–Utah (Path C)	South-to-north	1,250	PacifiCorp Path

* The ATC of a specific path may change based on changes in the transmission service and generation interconnection request queue (i.e., the end of a transmission service, granting of transmission service, or cancelation of generation projects that have granted future transmission capacity)

Existing Transmission Capacity for Firm Market Imports

The Idaho to Northwest, Idaho–Montana, and Idaho–Utah paths provide Idaho Power connections to market hubs in the west. Idaho Power's connections to market hubs are leveraged by the company as an equivalent to a resource for capacity position purposes. The quantity that each path provides toward the annual capacity position varies by season and year within the planning horizon.

Idaho to Northwest and Idaho-Montana Path Firm Market Imports

Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW is on the Idaho to Northwest path, and 80 MW is on the Idaho–Montana path.

Table 7.2 details a typical summer season transmission capacity utilization, which includes Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) capacity. CBM can only be accessed as firm capacity if Idaho Power is in an energy emergency. TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use on the Idaho to Northwest path for the purposes of grid reliability to ensure a safe and reliable transmission system. An additional discussion of CBM and TRM takes place later in the chapter.

Table 7.2 Pacific Northwest to Idaho Power west-to-east transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (MW)
BPA Load Service (Network Customer)	330
TRM	283
CBM	330
Subtotal	**943**
Pacific Northwest Purchase (Idaho Power Load Service)	337
Total	**1,280**

Idaho to Northwest Path Utilization

To utilize Idaho to Northwest transmission capacity for imports, Idaho Power must purchase transmission service from another party between the Mid-C market hub (or a direct entity in the Pacific Northwest) and the Idaho Power transmission system, and then use its transmission to deliver energy to the ultimate load. Typically, the company will reserve transmission with one of the other Idaho to Northwest path owners—Avista, BPA, or PacifiCorp—between Mid-C and the Idaho Power border. Table 7.3 details the summer allocation of the maximum amount that Idaho Power can reserve transmission with each entity to access resources from Mid-C to cross the Idaho to Northwest path.

Table 7.3 The Idaho to Northwest Path (WECC Path 14) summer allocation

Transmission Provider	Idaho to Northwest Allocation (Summer West-to-East) (MW)
Avista (to Idaho Power)	340
BPA (to Idaho Power)	350
PAC (to Idaho Power)	510
Total Capability to Idaho Power	**1,200***

* During times of very low generation at Brownlee, Oxbow, and Hells Canyon hydro plants, the Idaho to Northwest path total capability can increase to as much as 1,340 MW; low generation at these power plants does not correspond with Idaho Power's system peak

Idaho—Montana Path Utilization

Idaho Power's share of the Idaho–Montana path includes an 80 MW connection to either Avista, BPA, or Northwestern Energy across the Brady–Mill Creek 230-kV line, and a direct connection to Northwestern Energy across the Big Grassy–Dillon 161-kV line, which is not included in the total Pacific Northwest to Idaho Power import capacity due to commercial constraints beyond the Idaho Power border.

Like the Idaho to Northwest transmission path, to utilize the Idaho–Montana path capacity for imports, Idaho Power must purchase transmission service from another party between the purchased resource, such as the Mid-C market hub, and the Idaho Power transmission system.

Idaho—Utah Path Utilization

PacifiCorp is the owner and operator of the Idaho–Utah path. Idaho Power has secured 50 MW of transmission capacity, for firm resource imports to access the Desert Southwest market, between the months of June and October.

Existing Transmission Modeling in the 2023 IRP

Table 7.4 details the amount that Idaho Power leverages transmission connections, by market, season, and year, to meet peak demand. The company can use its existing transmission connections to provide 380 MW of firm summer capacity plus 200 MW of emergency summer capacity via CBM. The company can use its existing transmission connections to provide 330 MW of firm winter capacity through 2028. After 2028, the company assumes the firm winter capacity decreases from 330 MW to 100 MW by 2030. The reason for this modeled reduction is to conservatively move away from relying on the Pacific Northwest to provide the company with winter capacity because the Pacific Northwest is a winter peaking region. The company anticipates it will be more difficult for the Pacific Northwest to meet its winter peak obligations in the late-2020s.

Table 7.4 Third-party secured import transmission capacity for existing transmission

Third-Party Provider	Market	Summer Capacity (MW)	Winter Capacity 2024–2028 (MW)	Winter Capacity 2028–2029 (MW)	Winter Capacity 2029–2043 (MW)
Avista via Lolo	Pacific Northwest	200	200	165	50
PAC via Walla Walla	Pacific Northwest	80	80	0	0
BPA via La Grande	Pacific Northwest	50	50	50	50
PAC via Red Butte (Utah–Nevada border)	Desert Southwest	50	0	0	0
Subtotal		**380**	**330**	**215**	**100**
Emergency Transmission (CBM)	Pacific Northwest	200	0	0	0
Total		**580**	**330**	**215**	**100**

Capacity Benefit Margin Details

CBM is transmission capacity Idaho Power sets aside on the company's transmission system, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. An energy emergency must be declared by Idaho Power before the CBM transmission capacity becomes firm. The company holds 330 MW of import transmission capacity aside on the Idaho to Northwest path for CBM. For the 2023 IRP, Idaho Power has reduced the contribution of CBM toward the annual capacity position from 330 MW for all seasons to 200 MW in the summer and 0 MW in the winter. For operational purposes, Idaho Power continues to set aside 330 MW on the transmission system. The reduction of capacity credit to 200 MW in the summer is in response to continued transmission market limitations beyond the Idaho Power border because CBM capacity does not have corresponding third-party transmission reservations to the Mid-C market. The reduction of winter season CBM capacity to 0 MW is in response to winter wholesale energy market depth concerns from the Pacific Northwest. Idaho Power will continue to evaluate CBM in the future to determine whether the capacity credit accurately reflects Idaho Power's ability to utilize the transmission outside of Idaho Power's border.

Transmission Reliability Margin Details

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use on the Idaho to Northwest path for the purposes of grid reliability to ensure a safe and reliable transmission system. Idaho Power's TRM methodology, approved by the FERC in 2002, requires Idaho Power to set aside transmission capacity based on the average adverse unscheduled flow on the Idaho to Northwest path.

In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. However, physics dictates the actual power flow over the path based on the path of least resistance, so actual flows don't equal contract path schedules. The difference between scheduled and actual flow is referred to as unscheduled flow.

Boardman to Hemingway

In the 2006 IRP, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a 230-kV line interconnecting at the McNary substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including evaluating upgrade options of existing transmission lines, evaluating terminus locations, and sizing the project to economically meet the needs of Idaho Power and other regional participants. The project has evolved into what is now B2H. The project, which is expected to provide a total of 2,050 MW of capacity[32], involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn substation near Boardman, Oregon, and the existing Hemingway substation in southwest Idaho. The new line will provide many benefits for Idaho Power, including the following:

- Greater access to the Pacific Northwest electric market to economically serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and resiliency
- Reduced capacity limitations on the regional transmission system as demands on the system continue to grow

The benefits of B2H in aggregate reflect its importance to the achievement of Idaho Power's goal to provide 100% clean energy by 2045 without compromising the company's commitment to reliability and affordability.

The B2H project has been identified as a preferred resource in IRPs since 2009 and ongoing permitting activities have been acknowledged in every IRP Near-Term Action Plan thereafter. The 2017 IRP, 2019 IRP, and 2021 IRP Near-Term Action Plans, including B2H construction related activities mentioned within, were acknowledged by both the Idaho and Oregon PUCs.

[32] B2H is expected to provide 1,050 MW of capacity in the west-to-east direction, and 1,000 MW of capacity in the east-to-west direction.

B2H is a regionally significant project; it was identified as a key transmission component of each Northern Tier Transmission Group biennial regional transmission plan for 10 years 2010–2019. The B2H project is similarly a major component of the 2020–2021 NorthernGrid regional transmission plan. Further, the draft 2022–2023 NorthernGrid regional transmission plan includes the B2H project as a major component.

B2H Value

Idaho Power received acknowledgment of B2H in the 2021 IRP based on the company owning 45% of the project. Under the current ownership structure, which was modified in 2023, Idaho Power absorbed BPA's previously assumed ownership share in exchange for BPA entering into a transmission service agreement with Idaho Power.

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

- Planning Conditions Preferred Portfolio NPV—$9,746 million
- Planning Conditions without B2H Portfolio NPV—$10,582 million
- B2H NPV Cost Effectiveness Differential—$836 million

Under planning conditions, the Preferred Portfolio is approximately $836 million more cost effective than the portfolio that did not include B2H. For comparison, the cost effectiveness of the 2023 IRP's Preferred Portfolio (with B2H) is more than triple the cost effectiveness of the Preferred Portfolio (with B2H) in the 2021 IRP; the 2021 IRP Preferred Portfolio with B2H was $266 million more cost effective than the non-B2H alternative. Detailed portfolio costs can be found in Chapter 10.

There are four primary reasons for the increased benefits associated with B2H:

1. Competing IRP resources have also experienced cost increase pressures.
2. In the 2021 IRP, the company modeled the termination of 510 MW of transmission-service-related revenue upon the completion of B2H. In the 2023 IRP, following discussions with the transmission customer, Idaho Power is no longer assuming termination of this service. This change resulted in the addition of wheeling revenue related to this service and the adjustment of Midpoint West available transmission capacity for determining the GWW transmission trigger levels from resource additions.
3. The company's summer load growth has grown in the years directly following B2H in-service date, further increasing the cost effectiveness of the project by avoiding a significant amount of new generation resources that would be required to meet demand in a non-B2H environment.

4. The company’s winter needs, which were not a major consideration in the 2021 IRP, have accelerated due to industrial load growth. The company’s B2H related asset exchange with PacifiCorp enables 200 MW of additional winter connectivity.

Project Participants

For the 2023 IRP, Idaho Power modeled the anticipated B2H capacity allocation shown in Table 7.5. The Idaho Power capacity allocation accommodates Idaho Power’s capacity needs for load service and for the anticipated new network transmission service BPA will be taking across the Idaho Power system to reach their southeast Idaho customers.

Table 7.5 B2H capacity allocation

	Idaho Power	PacifiCorp
Capacity (MW) west-to-east	750	300
Capacity (MW) east-to-west	182	818
Cost allocation	45%	55%

Figure 7.2 shows the transmission line route submitted to the ODOE in 2017.

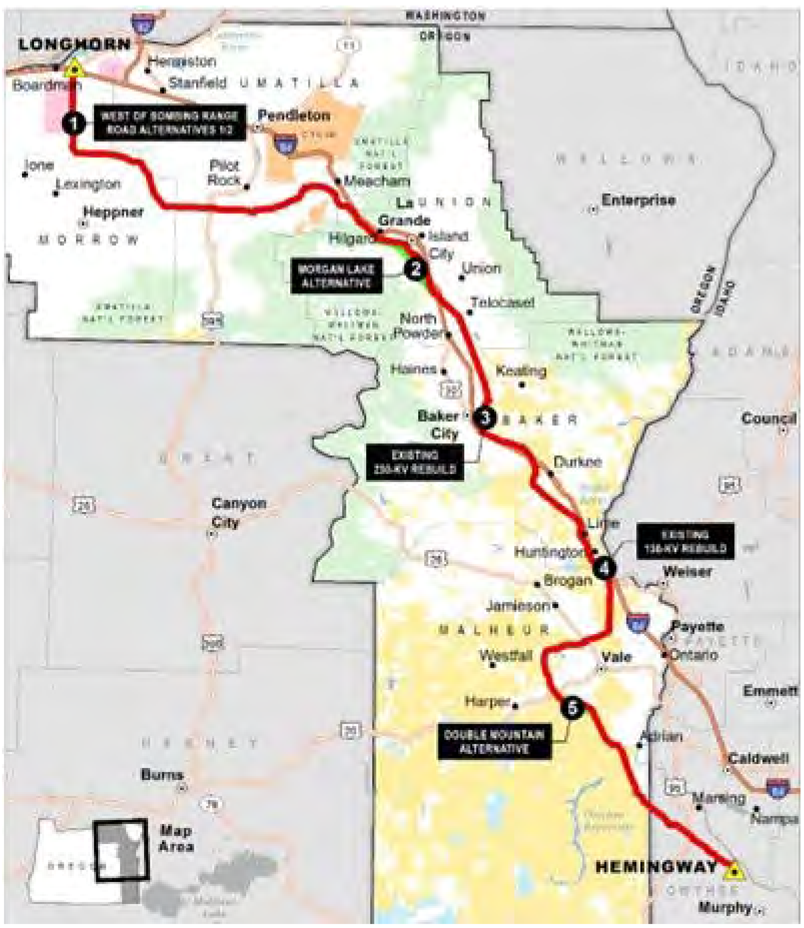


Figure 7.2 B2H route submitted in 2017 Oregon Energy Facility Siting Council Application for Site Certificate

B2H Related Asset Exchange—Four Corners Capacity

As part of the broader B2H transaction with PacifiCorp, Idaho Power has executed agreements to acquire PacifiCorp transmission assets and their related capacity sufficient to enable Idaho Power to use 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus substation) and Four Corners, through Mona. Four Corners is a Desert Southwest market hub with eight entities having transmission connectivity. Idaho Power will also have a connection to entities at Mona in central Utah.

Table 7.6 List of transmission entities at Four Corners and Mona

Entities with Transmission at Four Corners	Entities with Transmission at Mona
Arizona Public Service	Intermountain Power Agency (LADWP)
Salt River Project	PacifiCorp
Tri State G&T	
Western Area Power Admiration	
Xcel Energy	
Public Service New Mexico	
Tucson Electric Power Company	
PacifiCorp	

Idaho Power believes the acquired Four Corners capacity will provide the company with long-term strategic value diverse from the Pacific Northwest value provided directly by B2H. The Desert Southwest is rich with solar potential which is expected to continue its growth in the future. New Mexico has high wind potential, and the number of Desert Southwest entities with a presence at this market hub presents market diversity opportunities.

Through the direct B2H project, and the companion B2H enabled asset exchange with PacifiCorp, the B2H project is enabling two diverse connections to two major western market hubs.

Permitting Update

Permitting of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), United States Forest Service, United States Navy, and the Oregon Energy Facility Siting Council (EFSC). The federal permitting process is dictated primarily by the *Federal Land Policy Management Act and National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On November 25, 2016, BLM published the Final EIS, and the BLM issued a record of decision (ROD) on November 17, 2017, approving a right-of-way grant for the project on BLM-administered lands.

The United States Forest Service issued a separate ROD on November 13, 2018, approving the issuance of a special-use authorization for a portion of the project that crosses the Wallowa–Whitman National Forest.

The Department of Defense issued its ROD on September 25, 2019, approving a right-of-way easement for a portion of the project that crosses the Naval Weapons System Training Facility in Boardman, Oregon.

On August 4, 2021, a federal district court in Oregon issued an order granting Idaho Power and the federal defendants' motions for summary judgment, dismissing the Stop B2H Coalition's challenge to the BLM and Forest Service's issuance of the rights-of-way. That order was not appealed to the Ninth Circuit Court of Appeals within the requisite timeframe, and thus the district court's decision upholding the federal rights-of-way is not subject to appeal.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate to EFSC in February 2013 and submitted an amended preliminary Application for Site Certificate in summer 2017. The amended preliminary Application for Site Certificate was deemed complete by ODOE in September 2018. The ODOE reviewed Idaho Power's application for compliance with EFSC siting standards and released a Draft Proposed Order (DPO) for B2H on May 22, 2019. Public comment on the DPO findings were taken by ODOE and EFSC, and—based on those comments—ODOE issued a Proposed Order on July 2, 2020. A contested case on the Proposed Order was initiated and was presided over by an EFSC-appointed Administrative Law judge. The EFSC completed the contested case proceeding in 2022. In late September, the Oregon EFSC held its final hearing and its final vote on Idaho Power's application for a site certificate for B2H. The EFSC approved the site certificate by a unanimous vote. Three limited parties filed appeals to the Oregon Supreme Court asking them to overturn EFSC's approval of the B2H site certificate. The Oregon Supreme Court issued its decision on March 9, 2023, affirming the B2H site certificate.

Idaho Power has filed two Requests for Amendment (RFA) to the B2H site certificate. The RFAs are intended to provide additional flexibility during construction and to accommodate landowner requests where practicable. The first RFA (RFA1) was filed on December 7, 2022, and a Proposed Order was issued on August 7, 2023. Idaho Power expects a Final Order on RFA1 in fall 2023. The second RFA (RFA2) was filed on June 30, 2023, and is currently under review by EFSC.

Idaho Power also obtained Certificates of Public Convenience and Necessity from the IPUC and OPUC in June 2023.

The permit process in Idaho will consist of Conditional Use Permits issued by Owyhee County.

Although Idaho Power has non-appealable right-of-way grants from the BLM and the site certificate from ODOE, both entities require additional steps prior to authorizing construction.

Idaho Power is working through the BLM's process to secure Notice(s) To Proceed approvals and with the ODOE to obtain Pre-Construction Compliance Determinations. Idaho Power expects these authorizations to be granted in phases between the first quarter of 2023 and third quarter of 2024. Additionally, Idaho Power is in the process of securing bids and awarding contracts for the various aspects of the project to move into the construction phase.

Idaho Power expects construction to begin in 2023, with the line in service in 2026.

Construction Update Next Steps

B2H began pre-construction activities in 2021. These activities included, but are not limited to, the following:

- Geotechnical surveys
- Detailed ground surveys (light detection and ranging [LiDAR] surveys)
- Final environmental and cultural resource surveys
- Right-of-way activities
- Detailed design
- Constructability analysis
- Construction bid package development
- Long-lead material acquisition

At this time, the B2H project is preparing to commence construction activities in fall 2023. Construction activities include, but are not limited to, the following:

- Award of construction and material contracts
- Right-of-way clearing and access road construction
- Transmission line construction
- Substation construction or upgrades

Additional project information is available at idahopower.com/b2h.

B2H Modeling in the IRP

The B2H transmission project provides capacity associated with 1) the B2H transmission line directly and 2) the B2H enabled asset exchange.

B2H will add 1,050 MW of west-to-east capacity, and 1,000 MW of east-to-west capacity to the Idaho to Northwest path. Idaho Power will own 45% of the capacity in the form of 750 MW in the west-to-east direction, and 182 MW in the east-to-west direction. PacifiCorp will own the balance. The full B2H capacity is modeled in the transmission portion of AURORA, with separate transmission links modeled for Idaho Power's share and PacifiCorp's share. The company treats approximately 500 MW of B2H's summer capacity as equivalent to a summer resource. B2H west-to-east capacity will also be utilized by the company to provide transmission service to BPA.

The B2H asset exchange related capacity is modeled in the AURORA transmission links model as a 200 MW bi-directional connection between Idaho Power and Arizona Public Service. The company treats 200 MW of winter import capacity as equivalent to a winter resource.

B2H Cost Treatment in the IRP

In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. Transmission wheeling revenues, however, are not included in AURORA calculations. To remedy this inconsistency, starting in the 2019 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios. In the 2023 IRP, Idaho Power continued to model expected incremental third-party wheeling revenues as a reduction in costs ultimately benefiting retail customers.

Idaho Power's transmission assets are funded by native load customers, network customers, and point-to-point transmission wheeling customers based on a ratio of each party's usage of the transmission system. For the 2023 IRP, Idaho Power modeled B2H with the company's 45% ownership interest. A portion of this 45% ownership interest is providing transmission service to BPA, with BPA transmission wheeling payments acting as a cost-offset to the overall B2H project costs. Additionally, portfolios involving B2H result in a higher FERC transmission rate than portfolios without B2H. Although B2H provides significant incremental capacity, and will likely result in increased transmission sales, Idaho Power assumed flat transmission sales volume as a conservative assumption (other than increased volumes associated with transmission network customers such as BPA). The flat sales volume, applied to the higher FERC transmission rate, results in a cost offset for IRP portfolios with B2H.

In 2023 IRP modeling, Idaho Power assumed its 45% share of the direct expenses of B2H, plus an Allowance for Funds Used During Construction (AFUDC) cost, plus a project contingency amount. Total Cost Estimate: $823 million, which includes $47 million in local interconnection upgrades. These values are from the September 2023 B2H project estimate based on actual bids received for materials and construction.

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and PacifiCorp to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming, to the Hemingway substation near Melba, Idaho. PacifiCorp is currently the project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 7.3 shows a map of the project identifying the authorized routes in the federal permitting process based on the BLM's November 2013 ROD for segments 1 through 7 and 10. Segments 8 and 9 were further considered through a Supplemental EIS by the BLM. The BLM issued a ROD for segments 8 and 9 on January 19, 2017. In March 2017, this ROD was rescinded by the BLM for further consideration. On May 5, 2017, the *Morley Nelson Snake River Birds of Prey National Conservation Area Boundary Modification Act of 2017* (H.R. 2104) was enacted. H.R. 2104 authorized the Gateway West route through the Birds of Prey area that was proposed by Idaho Power and PacifiCorp and supported by the Idaho Governor's Office, Owyhee County and certain other constituents. On April 18, 2018, the BLM released the decision record granting approval of a right-of-way for Idaho Power's proposed routes for segments 8 and 9.

In its 2017 IRP, PacifiCorp announced plans to construct a portion of the Gateway West Transmission Line in Wyoming. PacifiCorp has subsequently constructed the 140-mile segment between the Aeolus substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming. The Aeolus to Anticline 500-kV line segment was energized in November 2020. In PacifiCorp's 2023 IRP, they selected the Anticline to Populus 500-kV to increase transmission for additional resource development within Wyoming.

Idaho Power has a one-third permitting interest in the segments between Midpoint and Hemingway (segment 8), Cedar Hill and Hemingway (segment 9), and Cedar Hill and Midpoint (segment 10). Further, Idaho Power has interest in the segment between Borah and Midpoint (segment 6), which is an existing transmission line operated at 345 kV but constructed at 500 kV.

Figure 7.3 Gateway West map

Gateway West will provide many benefits to Idaho Power customers, including the following:

- Relieve Idaho Power's constrained transmission system between the Magic Valley (Midpoint) and the Treasure Valley (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's core transmission system, connecting two major Idaho Power load centers.
- Provide the option to locate future generation resources east of the Treasure Valley
- Provide future load-service capacity to the Magic Valley from the Cedar Hill substation
- Help meet the transmission needs of the future, including transmission needs associated with VERs

The completed Gateway West project, as currently permitted, would provide approximately 4,000 MW of additional Midpoint West path transfer capacity between the Magic Valley and Treasure Valley. As detailed previously, Idaho Power has a one-third interest in the capacity additions between Midpoint and Hemingway. Along with the B2H project, Gateway West was a major component of the 2020–2021 NorthernGrid regional transmission plan. The draft 2022–2023 NorthernGrid regional transmission plan includes the B2H project and Gateway West segments 8 and 10. The Gateway West and B2H projects are complementary and will provide upgraded transmission paths from the Pacific Northwest across Idaho and into eastern Wyoming. Regional transmission plans produce a more efficient or cost-effective plan for meeting the transmission requirements associated with the load and resource needs of the regional footprint.

Gateway West—Segment 8 and Mayfield Substation

Gateway West segment 8 is the Midpoint–Hemingway #2 line segment of Gateway West. This line segment would be a new 500-kV line from the existing Midpoint substation near Shoshone, Idaho to Hemingway substation near Melba, Idaho. The earliest possible in-service date for this segment is end-of-year 2028. This segment of Gateway West will increase the Midpoint West and Boise East path capabilities by approximately 2,000 MW. As described earlier, Idaho Power has a one-third permitting interest in this segment, with PacifiCorp having the remaining majority interest. Idaho Power's capacity in this segment is anticipated to be 667 MW.

Along with the addition of Midpoint–Hemingway #2 line, a new Mayfield substation, located southeast of Boise, is anticipated to be required to integrate the 500-kV line and associated new resources into the Treasure Valley 230-kV system. The new Midpoint–Hemingway #2 line is anticipated to wrap into the Mayfield substation.

Gateway West—Segment 9 and Cedar Hills Substation

Gateway West segment 9 is the Cedar Hill–Hemingway 500-kV line segment of Gateway West. The Cedar Hill–Hemingway 500-kV line connects between the planned Cedar Hill substation near Murtagh, Idaho, and the Hemingway substation near Melba, Idaho. Together, the Midpoint–Cedar Hill (segment 10) and Cedar Hill–Hemingway 500-kV lines create a second new Gateway West 500-kV path for the company between the Magic Valley and Treasure Valley areas. Similar to Midpoint–Hemingway #2 500-kV, Cedar Hill–Hemingway 500-kV is expected to increase the Midpoint West and Boise East path capabilities by approximately 2,000 MW. The earliest possible in-service date is end-of-year 2030. Idaho Power has a one-third permitting interest in Cedar Hill–Hemingway 500-kV, with PacifiCorp maintaining the remaining majority interest. Idaho Power's capacity in this segment is anticipated to be 667 MW. The following is a map of the described Magic Valley to Treasure Valley Gateway West segments.

Gateway West—Segment 10

Gateway West segment 10 is the Midpoint–Cedar Hill line segment of Gateway West. The Midpoint–Cedar Hill 500-kV line will provide connectivity between the existing Midpoint substation and a future Cedar Hill substation, and likely the future Populus–Cedar Hill 500-kV line, prior to Cedar Hill substation being constructed. The Midpoint–Cedar Hill 500-kV segment is necessary to pair with PacifiCorp's Populus–Cedar Hill 500-kV segment to enable PacifiCorp to use its capacity gained via participation in the Midpoint–Hemingway #2 500-kV line. Therefore, the company assumes Midpoint–Cedar Hill will necessarily correspond with the construction of Midpoint–Hemingway #2.

Gateway West Cost Treatment and Modeling in the 2023 IRP

Gateway West map–Magic Valley to Treasure Valley segments 8, 9, and 10.

Similar to the B2H project, Idaho Power is working with PacifiCorp to develop the Gateway West transmission project, which is made up of several distinct phases listed in Table 7.7. While B2H provides Idaho Power additional access to the liquid Mid-C market hub, and therefore acts as a stand-alone resource, the Gateway West project serves a different function. Gateway West enables additional resources to be interconnected onto the Idaho Power transmission system east of the Treasure Valley. Without Gateway West the quantity of incremental resources is constrained.

The transmission capacity associated with Gateway West can relieve three primary transmission constraints: 1) transmission capacity between eastern Idaho and the Magic Valley (Borah West); 2) transmission capacity between the Magic Valley and the Treasure Valley (Midpoint West); and 3) transmission capacity between the Mountain Home area and the Treasure Valley (Boise East). The primary transmission constraints for adding new resources east of the Treasure Valley are the Midpoint West and Boise East paths. The Gateway West segment 8, segment 9, and segment 10 projects increase the transfer capability for both the Midpoint West and Boise East paths.

For the 2023 IRP, the company allowed 1,725 MW of incremental wind and solar resources to be interconnected to the existing grid, between 2024 and 2028, prior to the need to construct the first phase of Gateway West. Beyond 1,725 MW of incremental wind and solar, the analysis modeled each subsequent Gateway West addition as enabling 1,000 MW of incremental resources onto the system. This 1,000 MW level was chosen above the anticipated 667 MW capacity increase for each addition due to anticipated diversity among network generation resources (all resources likely will not be at maximum output) and the opportunity to use other methods, such as remedial action schemes or dynamic line ratings, to further optimize transmission flow and resource interconnections.

After the two permitted Gateway West projects, the 2023 IRP modeled a future not yet permitted transmission addition, Midpoint–Mayfield 500-kV. The IRP analysis modeled the earliest possible in-service date as end-of-year 2039. The Midpoint–Mayfield 500-kV line allowed for 2,000 MW of additional wind and solar resources. The company expects that the Midpoint–Mayfield 500-kV line could be a rebuild of an existing 230-kV line. The company has not begun permitting this line and expects to own all the capacity associated with the upgraded line.

The Gateway West phase 2023 IRP modeling costs and assumptions are listed in Table 7.7.

Table 7.7 Gateway West phase modeling

Phase	In-Service Date*	Incremental Resource Capacity Enabled	Cost (Levelized per year)**
Midpoint–Hemingway #2 500-kV (Segment 8), and Midpoint–Cedar Hill 500-kV (Segment 10), and Mayfield substation	12/2028*	1,000	$42.3 million
Cedar Hill–Hemingway 500-kV (Segment 9) and Cedar Hill substation	12/2030*	1,000	$25.2 million
Future non permitted phase: Midpoint–Mayfield 500-kV	12/2039	2,000	$21.7 million

*Idaho Power will continue to work with PacifiCorp on the timing and need for these Gateway West segments.

**The levelized costs in this table do not reflect offsetting transmission revenues from Idaho Power transmission customers.

To determine a cost-estimate for each phase, the company used costs associated with its Gateway West federal permit, transmission cost-per-mile estimates for B2H, and 500-kV substation estimates.

Southwest Intertie Project-North

Southwest Intertie Project-North (SWIP-N) is a proposed 285-mile 500-kV transmission line being developed by Great Basin Transmission, LLC. SWIP-N would connect Idaho Power's Midpoint substation near Shoshone, Idaho, and the Robinson Summit substation near Ely, Nevada. The project would provide a connection to the One Nevada 500-kV Line (ON Line), which is an in-service transmission line between Robinson Summit and the Harry Allen substation in the Las Vegas, Nevada, area. The two projects together are the combined SWIP. The combined SWIP portion of the project between Midpoint and Harry Allen has WECC-approved path ratings of 2,070 MW north-to-south and 1,920 MW south-to-north. The addition of SWIP-N creates 1,117.5 MW of north-to-south capacity and 1,072.5 MW of south-to-north capacity between Midpoint and Harry Allen for Great Basin Transmission.

Building on the SWIP-N sensitivity analysis performed in the previous 2021 IRP cycle that showed potential cost savings with participation in the project, Idaho Power performed additional analysis on the project in this IRP. The California Independent System Operator (CAISO) has also expressed interest in the SWIP-N project through their most recent 2022–2023 Transmission Plan. CAISO's primary interest in the project is in the north-to-south direction while Idaho Power's interest would be in the south-to-north direction to enable the company to access the Desert Southwest wholesale market hubs. The Desert Southwest region has a diverse seasonal load profile compared to Idaho Power and the Pacific Northwest. The market can be accessed to help serve future Idaho Power peak winter season needs.

As part of the 2023 IRP, Idaho Power analyzed SWIP-N as providing a 500 MW resource equivalent capacity, from the Desert Southwest, in the winter months beginning in 2027. Given the expected very high solar buildout in the southwest, the company also assumed SWIP-N could provide 50 MW of resource equivalent summer capacity in 2029, and 100 MW starting in 2030 through the remainder of the plan.

To investigate a potential alternative to SWIP-N, Idaho Power analyzed NV Energy's planned Greenlink Nevada transmission projects as an option for obtaining additional firm capacity to Desert Southwest markets. The Greenlink Nevada project consists of two proposed 500-kV transmission lines: Greenlink West from Las Vegas, Nevada, to Yerington, Nevada, and Greenlink North from Yerington, Nevada, to Robinson Summit substation near Ely, Nevada. While the project will create additional capacity internally within Nevada, it does not create capacity north of Robinson Summit from Nevada into Idaho. The Greenlink Nevada project is not a viable for option for Idaho Power to access Desert Southwest markets.

Southwest Market Opportunity

The SWIP-N project, similar to the Four Corners capacity, would enable Idaho Power to access the seasonal load diversity that exists between Idaho Power and utilities to the south. Figure 7.4, created from historical FERC 714 Balancing Authority Area (BAA) hourly load data, shows the gap that exists between the Desert Southwest summer and winter seasonal peaks. The large gap that exists between the seasonal summer and winter peaks indicates potential for excess capacity in the winter season from the southwest markets to help meet peak future demand needs for Idaho Power during winter.

SWIP-N Preliminary Route.

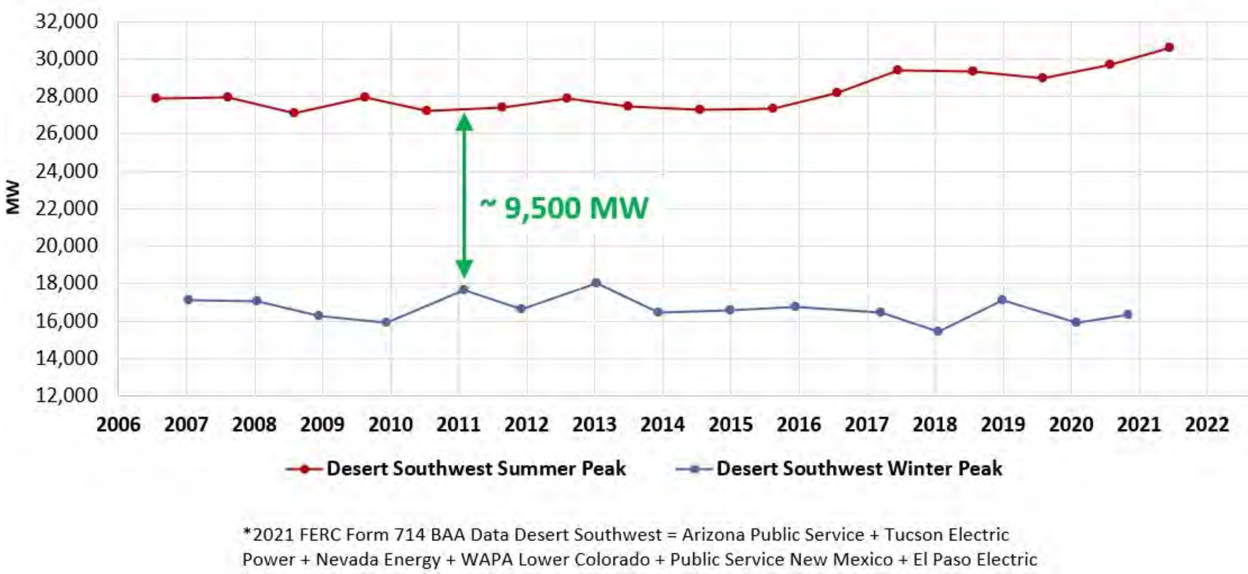


Figure 7.4 Historical Desert Southwest Summer and Winter Seasonal Peaks

The following Figure 7.5 is a forward looking forecast of the same Desert Southwest utilities from the 2021 FERC Form 714 data. The gap between the forecasted summer peak and the winter peak is projected to continue into the future.

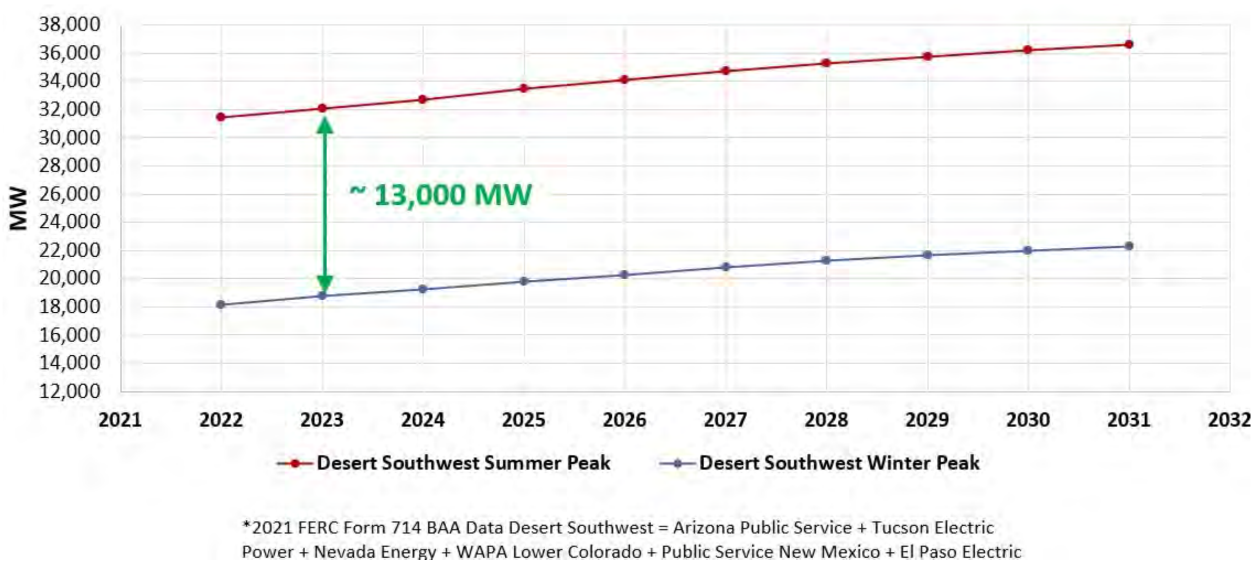


Figure 7.5 Forecasted Desert Southwest Summer and Winter Seasonal Peaks

Federal Funding Opportunities for Transmission

Idaho Power continues to monitor federal funding opportunities for transmission development. Most applicable to large transmission development is the federal Transmission Facilitation Program from the Bipartisan Infrastructure Law. The Transmission Facilitation Program provides federal support to help certain projects overcome initial financial hurdles. Under this program, the DOE could serve as an anchor customer by subscribing to up to 50% of a planned project's capacity. The DOE would then look to sell this contracted capacity to recover costs. To be eligible, the projects must be nearly "shovel ready" and be projects that would not otherwise be constructed without federal support. The Transmission Facilitation Program will not consider projects that are fully subscribed or have fully allocated sources of revenue. The B2H and Gateway West projects would not qualify for this program.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. Supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 7.8. The company assumed all resources were located east of the Treasure Valley. Backbone transmission assumptions include an assignment of the pro-rata share for transmission upgrades identified for resources east of Boise.

Transmission lines under construction at the Hemingway substation.

Table 7.8 Transmission assumptions and requirements

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumption
Hydrogen Combustion Turbine	170	Treasure Valley Area	Connection to 230-kV Bus *Local Transmission Upgrades Required*
Natural Gas CCCT	300	Treasure Valley Area	Connection to 230-kV Bus *Transmission Line Upgrades Required*
Natural Gas SCCT	170	Treasure Valley Area	Connection to 230-kV Bus *Local Transmission Upgrades Required*
Danskin 1 Retrofit *SCCT to CCCT Conversion*	90	Mountain Home Area	Connection to 230-kV Bus
Nuclear *SMR*	100	Eastern Idaho Area	Connection to 230-kV Bus *Transmission Upgrades Required*
Geothermal	30	Raft River Area	Assumes 138-kV Connection
Biomass *Indirect—Anaerobic Digester*	30	Magic Valley Area	Assumes 138-kV Connection
Solar PV *Utility-Scale 1-Axis Tracking*	100	Mountain Home Area	Connection to 230-kV Bus *Local Transmission Upgrades Required*
Wind—Wyoming	100	Within 5 Miles of Jim Bridger	Connection to 345-kV Bus
Wind—Idaho	100	Magic Valley Area	Assumes 345-kV Connection
Pumped Storage *New Upper Reservoir & New Generation/Pumping Plant*	250	Mountain Home Area	Assumes 138-kV Connection *Local Transmission Upgrades Required*
Short Duration Storage *Li-ion Battery 4-Hour*	50	Treasure Valley Area	Assumes 138-kV Connection
Short Duration Storage *Li-ion Battery 4-Hour, Distribution-Connected*	5	Treasure Valley Area	Assumes Feeder Connection
Medium Duration Storage *Li-ion Battery 8-Hour*	50	Treasure Valley Area	Assumes 138-kV Connection
Multi-Day Duration Storage *Iron-Air Battery 100-Hour*	50	Treasure Valley Area	Assumes 138-kV Connection

8. PLANNING PERIOD FORECASTS

The IRP process requires numerous forecasts and estimates, which can be grouped into four main categories:

1. Load forecasts
2. Generation forecasts for existing resources
3. Natural gas price forecasts
4. Resource cost estimates

Chobani plant near Twin Falls, Idaho.

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to inform the IRP model in developing portfolio buildouts. The following sections provide details on the forecasts prepared as part of the 2023 IRP.

Load Forecast

Each year, Idaho Power prepares a forecast of energy sales. This forecast is a product of historical system data and trends in electricity usage along with numerous external economic and demographic factors.

Idaho Power has its annual peak demand in the summer, with peak loads driven by irrigation pumps and air conditioning in June through September. Historically, Idaho Power's growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. Both measures are important in planning future resources and are part of the load forecast prepared for the 2023 IRP.

The anticipated average load and peak-hour demand forecasts represent Idaho Power's most probable outcomes for load requirements during the planning period. In addition, Idaho Power prepares other probabilistic load forecasts to address the load variability associated with abnormal weather and economic scenarios.

The anticipated forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*.
For example, the anticipated annual average system load growth of 2.1% (over the period 2024 through 2043) comprises a residential load growth of 1.1%, a commercial load growth of 0.8%, an irrigation load growth of 0.6%, an industrial load growth of 1.3%, and an additional firm load growth of 9.1%. Given notable anticipated growth from industrial customers, the forecast

annual system load growth over the five-year period from 2024 through 2028 is 5.5%, disproportionately weighted to those industrial customers.

The number of residential customers in Idaho Power's service area is expected to increase 1.6% annually from 518,490 at the end of 2022 to nearly 724,000 by the end of 2043. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.1% average annual residential load-growth rate over the forecast term.

Significant factors that influenced the outcome of the 2023 IRP load forecast include, but are not limited to, the following items:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. In the anticipated load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Probabilistic variations of weather are also analyzed.
- The economic forecast used for the 2023 IRP reflects a softened expansionary economy in Idaho over the near-term and reversion to the long-term trend of the service-area economy. While Idaho had the highest residential population growth rate of any state in the nation for the five years ending 2020, customer growth and residential permit issuances have come down from those highs in 2022. However, net migration and business investment continues to result in positive economic activity.
- DSM impacts—including energy efficiency programs, codes and standards, and other naturally occurring efficiencies—are integrated into the sales forecast. These impacts are expected to continue to erode use per customer over much of the forecast period.
- New industrial and Energy Service Agreement (ESA) customer requests are inherently uncertain regarding location and capacity need. The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment or interest indicating a commitment of the highest probability of locating in the service area. The large number of businesses that have indicated some interest in locating in Idaho Power's service area and have not made sufficient commitments are not included in the anticipated-case sales and load forecast.
- The electricity price forecast used to prepare the sales and load forecast in the 2023 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2021 IRP Preferred Portfolio.

Weather Effects

The 50^{th}-percentile load forecast assumes average temperatures and precipitation over a 30-year meteorological measurement period, or normal climatology. This implies a 50% chance loads will be higher or lower than the anticipated load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation. However, the 30-year normal temperatures have been increasing over the past several decades, implying a cold bias in the calculation. Since actual loads can vary significantly depending on weather conditions, additional scenarios for an increased load requirement were analyzed to address load variability due to weather—the 70^{th}- and 90^{th}-percentile load forecasts. The 70^{th}-percentile weather was utilized in the anticipated case to adjust for any systemic historic changes.

Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather and climate. Idaho Power's peak electric power sales are bimodal over a year, with demand in Idaho Power's service area peaking during the summer months. Currently, summer months exhibit a reliance on the system for cooling load in tandem with requirements for irrigation pumps. A secondary peak during the winter months also occurs, driven primarily by colder temperatures and heating. Because Idaho Power is a predominantly summer peaking utility, timing of precipitation and temperature can impact which of those months' demand on the system is greatest. Idaho Power tests differing weather probabilities hinged on a 30-year normal period. A more detailed discussion of the weather-based probabilistic scenarios and seasonal peaks is included in *Appendix A—Sales and Load Forecast.*

Weather is the primary factor affecting the load forecast on a monthly or seasonal basis. During the forecast period, economic and demographic conditions also influence the load forecast.

Economic Effects

Numerous external factors influence the sales and load forecast that are primarily economic and demographic. Moody's Analytics is the primary provider for these sets of data. The national, state, Metropolitan Statistical Area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate said economic data include, but are not limited to, the United States Census Bureau, the Bureau of Labor Statistics, the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

The state of Idaho had the highest population growth rate in the nation for several years, ending in 2020. The number of households in Idaho is projected to grow at an annual rate of

1.6% during the forecast period, with most of the population growth centered on the Boise–Nampa MSA. The Boise MSA (or the Treasure Valley) encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. The number of households in the Boise–Nampa MSA is projected to grow faster than the state of Idaho, at an annual rate of 2.2% during the forecast period. In addition to the number of households, incomes, employment, economic output, and electricity prices are economic components used to develop load projections.

Idaho Power continues to manage a pipeline of prospective large-load customers (over 1 MW)—both existing customers anticipating expansion and companies considering new investment in the state—that are attracted to Idaho's positive business climate and low electric prices. Idaho Power's economic development strategy is focused on optimizing Idaho Power's generation resources and infrastructure by attracting new business opportunities to our service area in both Idaho and eastern Oregon. Idaho Power's service offerings are benchmarked against other utilities. The company also partners with the states and communities to support local economic development strategies, and coordinates with large-load customers engaged in a site selection process to locate in Idaho Power's service area.

The 2023 IRP average annual system load forecast reflects continued growth in the service area's economy. While the economic and demographic variables have softened in 2022, the long-term 2023 IRP forecast reflects a robust sales outlook through the planning period given the combination of the strong demographic horizon for Idaho and commercial and industrial investment activity.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 8.1 and Table 8.1 show the results of the three forecasts used in the 2023 IRP as annual system load growth over the planning period. There is an approximate 50% probability Idaho Power's load will exceed the 50th-percentile forecast, a 30% probability of load exceeding the 70th-percentile forecast (planning condition), and a 10% probability of load exceeding the 90th-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 2.1% over the 2024 through 2043 period.

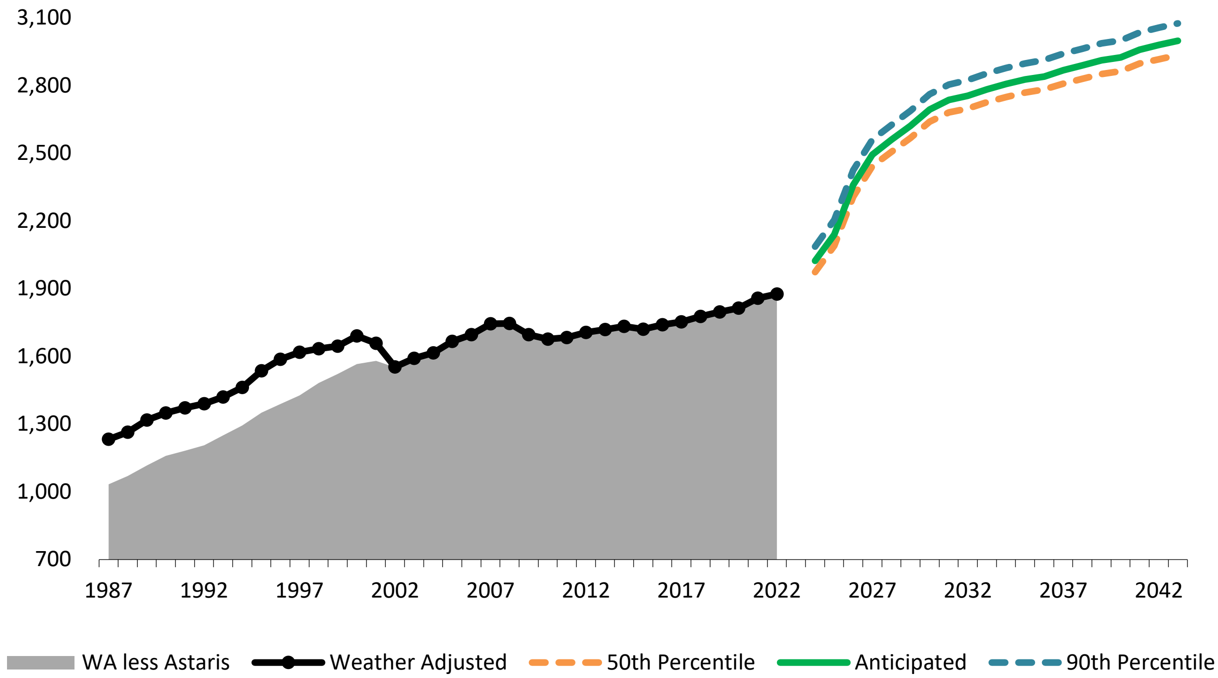


Figure 8.1 Average monthly load-growth forecast (aMW)

Table 8.1 Load forecast—average monthly energy (aMW)

Year	50th Percentile	Anticipated	90th Percentile
2024	1,974	2,024	2,087
2025	2,090	2,141	2,205
2026	2,308	2,360	2,425
2027	2,443	2,495	2,561
2028	2,507	2,561	2,627
2029	2,568	2,622	2,689
2030	2,640	2,695	2,763
2031	2,681	2,737	2,805
2032	2,699	2,755	2,825
2033	2,727	2,784	2,854
2034	2,749	2,807	2,878
2035	2,769	2,827	2,899
2036	2,783	2,841	2,914
2037	2,809	2,868	2,942
2038	2,830	2,890	2,964
2039	2,851	2,912	2,987
2040	2,865	2,926	3,001
2041	2,898	2,960	3,036
2042	2,917	2,980	3,057
2043	2,936	2,999	3,076
Growth Rate (2024–2043)	**2.1%**	**2.1%**	**2.1%**

Peak-Hour Load Forecast

The average-energy load forecast, as discussed in the preceding section, is an integral component of the load forecast. The peak-hour load forecast is similarly integral. Peak-hour forecasts are derived from the sales forecast, and as the impact of peak-day temperatures.

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as ESA customers.

Idaho Power's system peak-hour load record—3,751 MW—was recorded on Wednesday, June 30, 2021, at 7 p.m. Summertime peak-hour load growth accelerated in the previous decade as air conditioning became standard in nearly all new home construction and new commercial buildings. Growth in system peak demand slowed considerably in 2009, 2010, and 2011—the consequences of a severe recession that brought home and business construction to a standstill. Demand response programs have also been effective at reducing peak demand in the summer. The 2023 IRP load forecast projects annual peak-hour load to grow by approximately 80 MW per year throughout the planning horizon. The peak-hour load forecast does not reflect the company's demand response programs.

Idaho Power's winter peak-hour load record is 2,604 MW, recorded December 22, 2022, at 9 a.m. Historical winter peak-hour load is much more variable than summer peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

Figure 8.2 and Table 8.2 summarize four forecast outcomes of Idaho Power's estimated annual system peak load—50th-, 70th-, 90th-, and 95th-percentile. As an example, the 95th-percentile forecast uses the 95th-percentile peak-day average temperature to determine monthly peak-hour demand. Alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

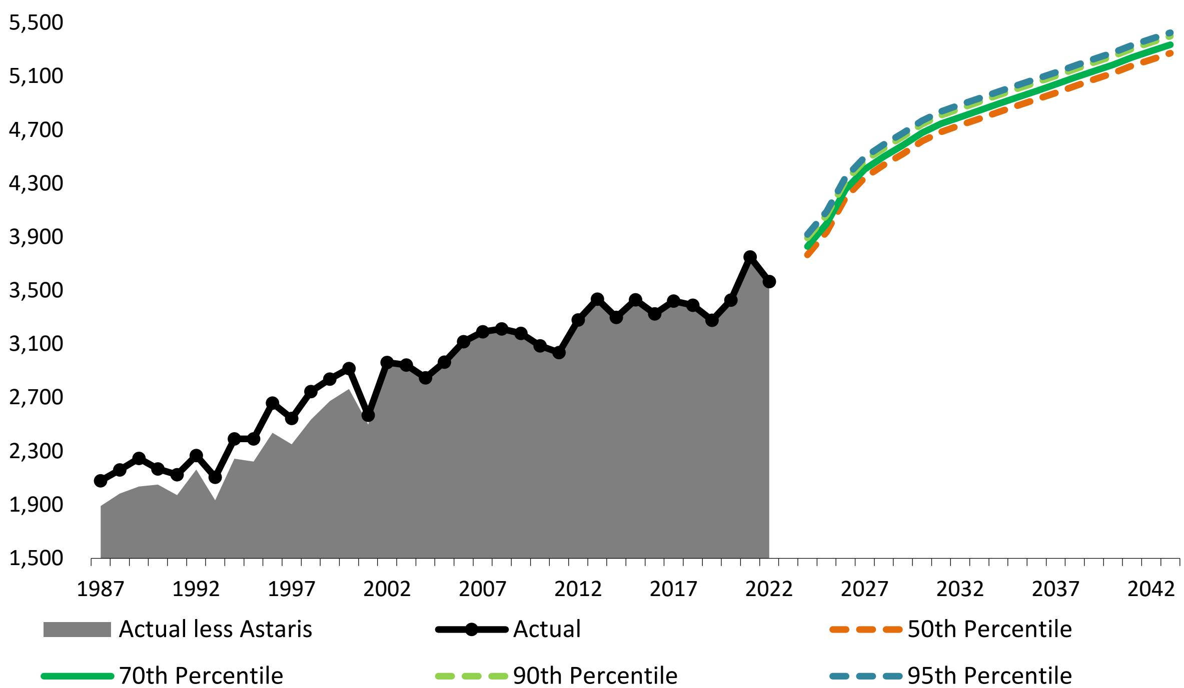


Figure 8.2 Peak-hour load-growth forecast (MW)

Table 8.2 Load forecast—peak hour (MW)

Year	50th Percentile	70th Percentile	90th Percentile	95th Percentile
2022 (Actual)	3,568	3,568	3,568	3,568
2024	3,767	3,830	3,894	3,920
2025	3,938	4,001	4,065	4,091
2026	4,193	4,256	4,320	4,347
2027	4,344	4,406	4,470	4,497
2028	4,439	4,501	4,565	4,592
2029	4,522	4,585	4,649	4,676
2030	4,616	4,679	4,743	4,769
2031	4,685	4,747	4,811	4,838
2032	4,735	4,797	4,861	4,888
2033	4,784	4,847	4,911	4,937
2034	4,834	4,897	4,961	4,987
2035	4,881	4,944	5,008	5,035
2036	4,930	4,992	5,056	5,083
2037	4,978	5,041	5,105	5,131
2038	5,028	5,091	5,155	5,181
2039	5,077	5,140	5,204	5,230
2040	5,125	5,188	5,252	5,279
2041	5,180	5,242	5,306	5,333
2042	5,227	5,290	5,354	5,381
2043	5,274	5,337	5,401	5,427
Growth Rate (2024–2043)	**1.8%**	**1.8%**	**1.7%**	**1.7%**

The 70th-percentile peak-hour load forecast predicts peak-hour load will grow to 5,337 MW by 2043—an average annual compound growth rate of 1.8%. The projected average annual compound growth rate of the 50th-percentile peak forecast is also 1.8%. The projected average annual compound growth rate of the 90th- and 95th-percentile peak forecasts is 1.7%.

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company to serve requests for electric service greater than 20 MW under an under a special contract, or ESA, schedule negotiated between Idaho Power and each large-power customer. The ESA and tariff schedule are approved by the appropriate state commission. An ESA allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

Individual energy and peak-demand forecasts are developed for ESA customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL; Brisbie, LLC

(Meta Platforms, Inc.); and several anticipated new ESA customers. These ESA customers comprise the entire forecast category labeled "additional firm load".

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs more than 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support; quality assurance; systems integration; and related manufacturing, corporate, and general services. Micron Technology's electricity use is a function of the market demand for its products.

Simplot Fertilizer

This facility, named the Don Plant, is located just outside Pocatello, Idaho. The Don Plant is one of four fertilizer manufacturing plants in the J.R. Simplot Company's Agribusiness Group. Vital to fertilizer production at the Don Plant is phosphate ore mined at Simplot's Smoky Canyon Mine on the Idaho–Wyoming border. According to industry standards, the Don Plant is rated as one of the most cost-efficient fertilizer producers in North America. In total, J.R. Simplot Company employs 2,000–3,000 people throughout its Idaho locations.

INL

INL is one of the United States DOE's national laboratories and is the nation's lead laboratory for nuclear energy research, development, and demonstration. The DOE, in partnership with its contractors, is focused on performing research and development in energy programs and national defense. Much of the work to achieve this mission at INL is performed in government-owned and leased buildings on the Research and Education Campus in Idaho Falls, Idaho, and on the INL site, approximately 50 miles west of Idaho Falls. INL is a critical economic driver and important asset to the state of Idaho with over 4,000 employees.

Brisbie, LLC (Meta Platforms, Inc.)

Idaho Power and Meta executed an ESA which was approved by the IPUC in May 2023. Meta has announced the construction of a new data center in Kuna, Idaho. With an estimated investment of $800 million, the Meta data center is projected to bring more than 1,200 jobs to Kuna during peak construction and 100 operational jobs. Meta plans to support 100% of its operations through the addition of new renewable resources connected to Idaho Power's system. The renewables support will be facilitated through a CEYW arrangement.

Generation Forecast for Existing Resources

Hydroelectric Resources

For the 2023 IRP, Idaho Power continues the practice of using 50th-percentile future streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 50thpercentile means basin streamflows are expected to exceed the planning criteria 50% of the time and are expected to be below the planning criteria 50% of the time.

C.J. Strike Dam near Mountain Home, Idaho.

Idaho Power uses a combination of two modeling methods to develop future flows for the IRP. The first method accounts for surface water regulation in the system and consists of two models built in the Center for Advanced Decision Support for Water and Environmental Systems RiverWare modeling framework, collectively referred to as the "Planning Models." The first of these models covers the spatial extent of the Snake River Basin from the headwaters to Brownlee Reservoir inflow. The second model takes the results of the first and regulates the flows through the HCC. The second method uses the Eastern Snake Plain Aquifer Model (ESPAM) to model aquifer management practices implemented on the ESPA. Modeling for the 2023 IRP used version 2.2 of the ESPAM. The two modeling methods used in combination produce a present-conditioned hydrologic record for the Snake River Basin from water year 1981 through 2018, where the water management system is representative of current conditions and operated according to current constraints and requirements. This model adjusted for present conditions is then further adjusted to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations that are expected to occur or be in place over the planning horizon. The 50th-percentile modeled streamflows are then derived from the results of the two Planning Models. Further discussion of flow modeling for the 2023 IRP is included in *Appendix C—Technical Report*.

Discharges from the ESPA to the Snake River, commonly referred to as "reach gains," have shown a declining trend for several decades. Those declines are mirrored in documented well-level and storage declines in the ESPA. Although reach gains improved from 2017 to 2020, drought conditions in 2021 and 2022 have resulted in a return to low discharges for some gauged springs. Since 2013, reach gains have remained below long-term historic median flows.

A water management practice affecting Snake River streamflows is the release of water to augment flows during salmon outmigration. Various federal agencies involved in salmon migration studies have, in recent years, supported efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to mimic the timing of naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years. Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2023 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August.

Monthly average generation for Idaho Power's hydroelectric resources is calculated within the Planning Models described in *Appendix C—Technical Report*. The Planning Models mathematically compute hydroelectric generation while adhering to the reservoir operating constraints and requirements.

A representative measure of the streamflow condition is the annual inflow volume to Brownlee Reservoir. Figure 8.3 shows historical annual Brownlee inflow volume as well as modeled Brownlee inflow distributions for each year of the 2023 IRP. The 2021 IRP modeling results for the 10^{th}-, 30^{th}-, 50^{th}-, 70^{th}-, and 90^{th}-percentiles are shown for reference only to benchmark the changes in modeled inflow between IRP cycles. As Figure 8.3 shows, the 2023 IRP modeling results are similar to the 2021 IRP inflow volume results. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The modeled inflows include reductions related to declining base flows in the Snake River and projected future management practices. As noted previously in this section, these declines are assumed to continue through the planning horizon.

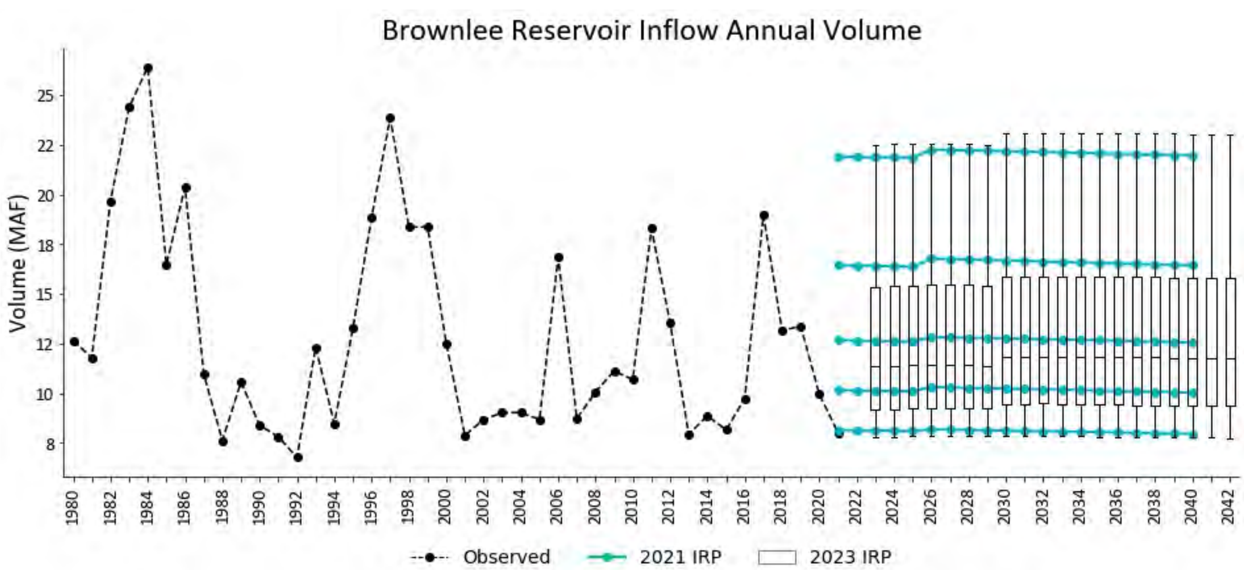


Figure 8.3 Brownlee inflow volume historical and modeled percentiles

Natural Gas Resources

Idaho Power owns and operates four natural gas SCCTs and one natural gas CCCT, having combined existing plant capacity of 716 MW (capacity MW at International Standards Organization (ISO) reference temperature of 59 degrees Fahrenheit). The company plans to continue to operate each of its existing gas units through the 20-year planning horizon. Idaho Power is monitoring alternative fuels, such as hydrogen, or hydrogen/natural-gas fuel blends, for potential use in the future at existing natural gas plants.

Natural Gas Price Forecast

Based on the methodologies employed by Idaho Power's peer utilities, as well as feedback received during IRPAC meetings, Idaho Power enlisted Platts, a well-known third-party vendor, as the source for the 2023 IRP planning case natural gas price forecast.

The Platts forecast information below was presented by the vendor representative at the October 13, 2022, IRPAC meeting.

The third-party vendor uses the following fundamentals to develop its gas price forecast:

- Supply and demand balancing network model of the North American gas market
- Oil and natural gas rig count data
- Model pricing for the entire North American grid
- Model production, transmission, storage, and multi-sectoral demand every month
- Individual models of regional gas supply/demand, pipelines, rate zones and structures, interconnects, capacities, storage areas and operations and combines these models into an integrated North American gas grid
- Solves for competitive equilibrium, which clears supply and demand markets as well as markets for transportation and storage

The following industry events helped inform the third-party 2023 natural gas price forecast used in the IRP analysis:

- Status of North American major gas basins (Figure 8.4) and pipeline capacity
- Oil prices and the associated gas production
- New and existing natural gas electric generation and the possible replacement of coal and nuclear capacity retirements
- Changes to residential and commercial customer gas demand from energy efficiency gains as well as policy changes that include new gas appliance service bans

- Global competition from gas producers (e.g., Russia and Qatar) and the role of liquefied natural gas exports (e.g., the United States and Australia)
- Possible policy changes at the federal level included carbon price and societal cost inclusion to natural gas as well as other wider energy policy developments

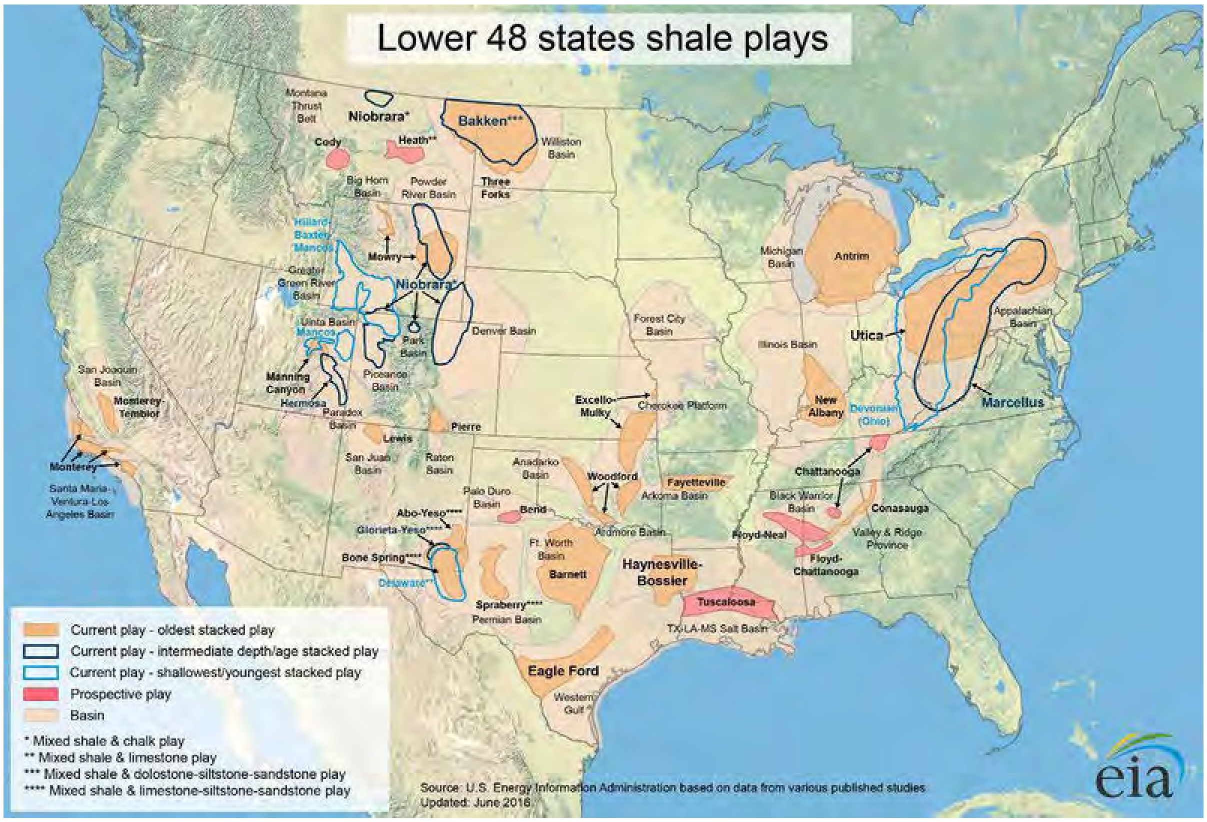


Figure 8.4 North American major gas basins

Platts' March 2023 Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington, served as the planning case forecast of fueling costs for existing and potential new natural gas generation on the Idaho Power system. Today, Sumas is the primary hub for Idaho Power's natural gas.

Because gas price forecasts are a significant driver of costs in the IRP process, Idaho Power also relied on EIA's alternative forecasts (High Oil and Gas Supply, and Low Oil and Gas Supply) from their Annual Energy Outlook 2023 to examine the impact of gas prices on the IRP. More details on the EIA forecasts can be found in their *Annual Energy Outlook 2023*.[33]

[33] United States EIA, *Annual Energy Outlook 2023* (AEO2023), (Washington, D.C., March 2023).

Natural Gas Transport

Ensuring pipeline capacity will be available for future natural gas generation will require the reservation of pipeline capacity before a prospective resource's in-service date. Consistent with the 2021 IRP, Idaho Power believes that turnback Northwest Pipeline capacity (existing contracts expiring without renewal) from Stanfield, Oregon, to Idaho—or even further south into the Opal and Rocky Mountain hub region—could serve the need for natural gas generating capacity for up to 600 MW of installed nameplate capacity and also augment fueling to converted coal to gas units at the Jim Bridger Plant located off the Mountain West Overthrust Pipeline. The 600 MW limit is derived from Northwest Pipeline's turnback capacity from Stanfield, Oregon, to Idaho as presented in Northwest Pipeline's spring 2023 Customer Advisory Board meeting.

Idaho Power projects (located in Idaho) that require additional natural gas generating capacity beyond an incremental 600 MW of capacity would require an expansion of Northwest Pipeline from the Rocky Mountain supply region to Idaho. Besides the uncertainty of acquiring capacity on existing pipeline beyond that necessary for 600 MW of incremental natural gas generating capacity, a pipeline expansion would provide diversification benefits from the current mix of firm transportation composed of 60% from British Columbia, 40% from Alberta, and no firm capacity from the Rocky Mountain supply region. In response to a request for a cost estimate for a pipeline expansion from the Rocky Mountain supply region, Northwest Pipeline calculated a levelized cost for a 30-year contract of $1.39/Million British Thermal Units (MMBtu) per day. It is assumed that any additional transportation would be procured in the short-term capacity release market, or through delivered supply transactions to cover 100% of the requirements on any given day.

Natural Gas Storage Facilities

The majority of natural gas consumed in the northwest comes from western Canada and the United States Rocky Mountain states. Most of this natural gas moves straight to end users through a network of interstate pipelines, local gas mains, and other utility infrastructure. Idaho Power also buffers a small share of its natural gas supply from underground storage facilities.

The first of these facilities is Jackson Prairie Underground Natural Gas Storage. It is located in Lewis County, Washington, about 100 miles south of Seattle. With 25 billion cubic feet of working gas, and being interconnected with Northwest Pipeline, Jackson Prairie plays an important role in ensuring reliable, cost-effective natural gas balancing service for Idaho Power customers during annual summer and winter peaks for natural gas and power demand.

The second facility is Spire Storage, located in Southwest Wyoming, near Evanston in Uinta County. This facility will have capacity available to Idaho Power in 2025. Due to its proximity to

Opal Hub, a working capacity of 35 billion cubic feet of gas and interconnectivity with five interstate pipelines, Spire Storage not only reliably and economically serves Idaho Power customers but all major markets in the western United States.

Both Jackson Prairie and Spire Storage facilities provide reliability in fuel supply, intra-day balancing for variable energy generation, and fueling diversity for Idaho Power's gas generation fleet.

Analysis of IRP Resources

For the 2023 IRP, Idaho Power continues to analyze resources based on cost, specifically the cost of a resource to provide energy and capacity to the system. In addition to the ability to provide flexible capacity, the system attributes analyzed include the ability to provide dispatchable capacity, non-dispatchable (i.e., coincidental) capacity, and energy. Importantly, energy in this analysis is considered to include not only baseload-type resources but also resources, such as wind and solar, that provide relatively predictable output when averaged over long periods (i.e., monthly, or longer). The resource attribute analysis also designates those resources whose variable production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are shown using two cost metrics: Levelized Cost of Capacity (LCOC) (fixed) and Levelized Cost of Energy (LCOE). These metrics are discussed later in this section. Resources are evaluated based upon their respective costs that will ultimately be funded by customers through rates. In most cases, as with company-owned supply-side resources, that represents a total resource cost (TRC) perspective. However, the TRC perspective is not exclusively applied in the IRP. Examples where TRC is not the cost perspective analyzed includes energy efficiency resources where the company incentivizes customer investment, and supply-side resources whose production is purchased under long-term contract (e.g., PPA and PURPA). Nevertheless, Idaho Power endeavors to conduct an evaluation of resource options using cost analyses that yield a like-versus-like comparison between resources, and consequently is in the best interest of customers.

In resource cost calculations, Idaho Power assumes potential IRP resources have varying economic lives. Financial analysis for the IRP assumes the annual depreciation expense of capital costs is based on an apportionment of the capital costs over the entire economic life of a given resource.

The levelized costs for the various resource alternatives analyzed include capital costs, O&M costs, fuel costs, and other applicable adders and credits (net of associated tax benefits). The initial capital investment and associated capital costs of resources include engineering development, generating and ancillary equipment purchase, installation, plant construction, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an AFUDC (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio in AURORA.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are provided in *Appendix C—Technical Report*.

LCOC—IRP Resources

The annual fixed revenue requirements, for each resource, are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month. Included in these LCOCs are the revenue requirements associated with initial resource investment and associated capital cost and fixed O&M estimates. Resources are considered to have varying economic lives, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. The expression of these costs in terms of kW of peaking capacity can have significant effect, particularly for VERs having peaking capacity significantly less than installed capacity. The LCOC values for the selectable 2023 IRP resources are provided in Table 8.3.

Table 8.3 Levelized cost of capacity (fixed) in 2024 dollars per kW per month

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Total Cost per kW/mo.
Clean Peaking Gas—Hydrogen Combustion Turbine	$8	$4	$12
Danskin 1 Retrofit—to CCCT Conversion	$23	$4	$26
Baseload Gas—CCCT	$14	$3	$17
Peaking Gas—SCCT	$9	$4	$12
Nuclear—SMR	$57	$25	$82
Geothermal	$33	$18	$51
Biomass	$31	$24	$54
Solar PV	$4	$3	$7
Wind—Wyoming	$5	$7	$12
Wind—Idaho	$7	$7	$14
Short Duration Storage—Li Battery (4 hour)	$12	$5	$17
Short Duration Storage—Li Battery (4 hour)—Dist. Connected	$11	$4	$15
Medium Duration Storage—Li Battery (8 hour)	$19	$8	$27
Long Duration Storage—Pumped Hydro (12 hour)	$30	$6	$36
Multi-Day Storage—Iron-Air Battery (100 hour)	$16	$4	$20

Note: columns may not perfectly add up due to rounding.

LCOE—IRP Resources

Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low (or zero) operating costs. The LCOE metric represents the estimated annual cost (revenue requirements) per MWh for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource. The LCOE assuming the expected capacity factors for each resource is shown in Table 8.4. Included in these costs are the capital cost, non-fuel O&M, and fuel costs. The cost of recharge energy for storage resources and the wholesale energy purchases and sales made available through B2H capacity are not included in the graphed LCOE values.

The LCOE is provided assuming a common online date of 2024 for all resources and based on Idaho Power specific financing assumptions. Idaho Power urges caution when comparing LCOE values between different entities or publications because the valuation is dependent on several underlying assumptions. The LCOE graphs also illustrate the effect of the ITC on storage resources, as well as the effect of the PTC on non-carbon emitting resources (like solar and wind). Idaho Power emphasizes that the LCOE is provided for informational purposes and is essentially a convenient summary metric reflecting the approximate cost competitiveness of different generating technologies. However, the LCOE is not an input into AURORA modeling performed for the IRP.

When comparing LCOEs between resources, consistent assumptions for the computations must be used. The LCOE metric is the annual cost of energy over the life of a resource converted into an equivalent annual annuity. This is like the calculation used to determine a car payment; however, in this case the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the LCOE calculation is the assumed level of annual energy output over the life of the resource being analyzed. The energy output is commonly expressed as a capacity factor. At a higher capacity factor, the LCOE is reduced because of spreading resource fixed costs over more MWh. Conversely, lower capacity factor assumptions reduce the MWh over which resource fixed costs are spread, resulting in a higher LCOE.

For the portfolio cost analysis, resource fixed costs are annualized over the assumed economic life for each resource and are applied only to the years of output within the IRP planning period, thereby accounting for end effects.

Table 8.4 Levelized cost of energy (at stated capacity factors) in 2024 dollars

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Total Cost per MWh	Capacity Factor
Clean Peaking Gas—Hydrogen Combustion Turbine	$68	$50	$191	$309	12%
Danskin 1 Retrofit —SCCT to CCCT Conversion	$56	$13	$46	$115	55%
Baseload Gas—CCCT	$36	$12	$42	$89	55%
Peaking Gas—SCCT	$98	$50	$66	$214	12%
Nuclear—SMR	$83	$42	$13	$139	94%
Geothermal	$50	$27	–	$78	90%
Biomass	$65	$61	$110	$236	64%
Solar PV	$17	$15	–	$31	31%
Wind—Wyoming	$16	$19	–	$35	47%
Wind—Idaho	$28	$25	–	$53	36%
Short Duration Storage—Li Battery (4 hour)	$97	$37	–	$134	17%
Short Duration Storage—Li Battery (4 hour)—Distribution-Connected	$88	$36	–	$124	17%
Medium Duration Storage—Li Battery (8 hour)	$77	$33	–	$111	33%
Long Duration Storage—Pumped Hydro (12 hour)	$82	$17	–	$99	50%
Multi-Day Storage—Iron-Air Battery (100 hour)	$148	$36	–	$184	15%

Note: columns may not perfectly add up due to rounding

Resource Attributes—IRP Resources

While the cost metrics described in this section are informative, caution must be exercised when comparing costs for resources providing different attributes to the power system. In other words, it is important to consider both the cost and the economic value of each individual resource. For the LCOC metric, this critical distinction between cost and economic value arises because of differences for some resources between installed capacity and peaking capacity. Specifically, for VERs, an installed capacity of 1 kW equates to an on-peak capacity of less than 1 kW. For example, Idaho wind is estimated to have an LCOC of $14 per month per kW of installed capacity. However, assuming wind delivers an ELCC equal to 20% of installed capacity, the LCOC ($14/month/kW) converts to $70 per month per kW of peaking capacity.

For the LCOE metric, the critical distinction between the cost and economic value of resources arises because of differences for some resources with respect to the timing at which MWh are delivered. For example, some resources have similar LCOEs. However, the energy output from one generating facility might tend to be delivered in a steady and predictable manner during peak-loading periods. Conversely, the energy output from another generating facility might tend to deliver during the high-value peak loading periods less dependably. Utilizing wind, for example, to meet peak demands can be effective when applying diversity (the wind may not be blowing in one location but is likely blowing in another). All these characteristics should be considered when comparing LCOEs for these resources.

In recognition of differences between resource attributes, potential IRP resources for the 2023 IRP are classified based on their attributes.

Table 8.5 Resource attributes

Resource	Variable Energy	Dispatchable Capacity-Providing	Balancing/ Flexibility-Providing	Energy Providing
Clean Peaking Gas—Hydrogen Combustion Turbine		✓	✓	✓
Danskin 1 Retrofit—SCCT to CCCT Conversion		✓	✓	✓
Baseload Gas—CCCT		✓	✓	✓
Peaking Gas—SCCT		✓	✓	✓
Nuclear—SMR		✓	✓	✓
Geothermal		✓		✓
Biomass		✓		✓
Solar PV	✓			✓
Wind—Wyoming	✓			✓
Wind—Idaho	✓			✓
Short Duration Storage—Li Battery (4 hour)		✓	✓	
Short Duration Storage—Li Battery (4 hour) – Dist. Connected		✓	✓	
Medium Duration Storage—Li Battery (8 hour)		✓	✓	
Long Duration Storage—Pumped Hydro (12 hour)		✓	✓	
Multi-Day Storage—Iron-Air Battery (100 hour)		✓	✓	
Energy Efficiency (Additional Bundles)				✓
Demand Response		✓		
B2H 500-kV Project		✓	✓	✓
SWIP-North 500-kV Project		✓	✓	✓

The following resource attributes are considered in this analysis:

- *Variable energy*—Renewable resources characterized by variable output and potentially causing an increased need for resources providing balancing or flexibility

- *Dispatchable capacity-providing*—Resources that can be dispatched as needed to provide capacity during periods of peak-hour loading or to provide output during generally high-value periods
- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from VERs
- *Energy-providing*—Resources producing energy or reducing energy needs that are relatively predictable when averaged over long time periods (i.e., monthly or longer)

Table 8.5 provides classification of potential IRP resources with respect to the above attributes. The table also provides cost information on the estimated size potential and scalability for each resource.

9. PORTFOLIOS

Throughout the 2023 IRP analysis, Idaho Power conducted an extensive review of IRP model inputs, system settings and specifications, and model validation and verification. The objective of the review was to ensure accuracy of the company's modeling methods, processes, and ultimately, the IRP results. The following sections describe the analysis process.

Capacity Expansion Modeling

For the 2023 IRP, and consistent with prior IRPs, Idaho Power used the LTCE capability of AURORA to produce optimized portfolios under various future conditions. The logic of the LTCE model optimizes resource additions and exits for each zone defined within the WECC. As Idaho Power's electrical system was modeled as a separate zone, the resource portfolios produced by the LTCE and examined in this IRP are optimized for Idaho Power. The optimized portfolios discussed in this document refer to the addition of supply-side and demand-side resources for Idaho Power's system and exits from current coal-generation units and converted natural gas units.

The selection of new resources in the optimized portfolios maintain sufficient reserves as defined in the model. To ensure the AURORA-produced optimized portfolios provided the least-cost, least-risk future, the 2023 IRP analysis tested resource and transmission configurations to find the Preferred Portfolio. These portfolios are discussed further in the following sections.

For most scenarios, including planning conditions, the 2023 IRP portfolios selected from a broad range of resource types, as well as varied amounts of nameplate generation additions:

- • Wind and solar (combination between 0 and 4,400 MW in total)
    - Wind (between 0 and 1,800 MW in total)
        - Wyoming (between 0 and 800 MW)
        - Idaho (between 0 and 1,800 MW)
    - Solar (between 0 and 2,600 MW in total)
        - Standalone (between 0 and 2,600 MW)
- Standalone storage (between 0 and 7,200 MW in total)
    - Pumped hydro (between 0 and 500 MW)
    - Battery energy storage
        - 4-hour transmission-connected (between 0 and 4,000 MW)
        - 4-hour distribution-connected (between 0 and 100 MW)

        - 8-hour transmission-connected (between 0 and 2,400 MW)
        - 100-hour transmission-connected (between 0 and 200 MW)
- Gas combustion (between 0 and 1,892 MW in total)
    - CCCT (between 0 and 561 MW)
        - New natural gas CCCT (between 0 and 300 MW)
        - Danskin retrofit (between 0 and 261 MW)
    - SCCT (between 0 and 720 MW)
        - Natural gas SCCT (between 0 and 340 MW)
        - Hydrogen SCCT (between 0 and 340 MW)
    - Coal to natural gas conversion of Jim Bridger units 3 and 4 (between 0 and 350 MW)
    - Coal to natural gas conversion of Valmy units 1 and 2 (between 0 and 261 MW)
- Nuclear SMR (between 0 and 1,200 MW)
- Biomass (between 0 and 150 MW)
- Geothermal (between 0 and 150 MW)
- Demand response (between 0 and additional 180 MW)
    - Existing program expansion (between 0 and 100 MW)
    - Pricing based programs (between 0 and 20 MW)
    - Storage based programs (between 0 and 60 MW)

Capacity Planning Reserve Margin

For reliability planning purposes, Idaho Power plans to a position of capacity length as derived from the 0.1 event-days per year LOLE threshold. One of the AURORA LTCE model's objectives is to meet a pre-determined PRM. Therefore, a translation is required between the probabilistic LOLE analysis and the PRM calculation as necessitated by the AURORA LTCE model. Idaho Power implements the LOLE methodology through the internally developed RCAT, which is capable of calculating two of the necessary components of the PRM calculation: the resource ELCC values and the capacity position. The PRM metric can be defined as the percentage of expected capacity resources above forecasted peak demand. The PRM and ELCC values that are calculated using the LOLE methodology are a direct input to the AURORA LTCE model. After AURORA solves for and produces portfolios, select resource buildouts and their corresponding data are analyzed with the LOLE methodology and tested to ensure they meet the predesignated reliability hurdle through the calculation of annual capacity positions. This model consolidation process is laid out in further detail in Figure 9.1.

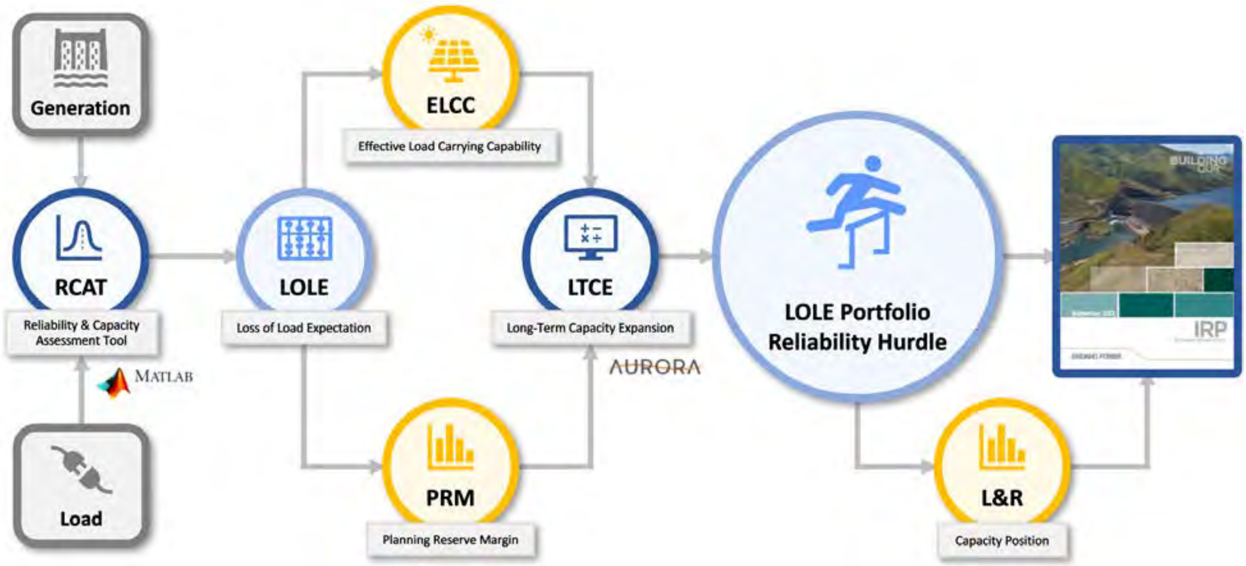


Figure 9.1 Idaho Power's reliability flowchart

In the 2021 IRP, the company derived static PRM and resource ELCC values that were held constant throughout the 20-year planning horizon. As the RCAT and AURORA serve different purposes in Idaho Power's planning process, the company recognized that further efforts were needed to translate and align the data exchanged between the two models. Historically, the PRM was based on the peak load of a given year plus some additional amount to account for abnormal weather events or equipment outages. This method worked well to ensure reliability for Idaho Power as a summer peaking utility with mostly flexible generation resources. As the wider industry, and the company, moves towards VERs whose hour-to-hour and season-to-season generation changes, it is no longer viable to only contemplate peak hour requirements.

To ensure that AURORA would recognize similar capacity needs as identified by the RCAT, the company developed seasonal PRM values for years in the planning horizon that experience significant changes in the resource buildout. While the capacity position calculated to assess reliability is still evaluated on an annual basis because of Idaho Power's 0.1 event-days per year LOLE threshold, providing summer and winter PRM values to AURORA is a better representation of the seasonal resource needs. The minimum seasonal PRM values in AURORA were updated at different points in the planning horizon to capture the effect of significant changes in the resource buildout. Historically, when a portfolio added predominantly flexible generation resources it was also sufficient to give these resources a static peak capacity contribution (or ELCC) as it was harmonious with a static PRM. As VER and Energy Limited Resources (ELR) additions increase, static values no longer account for the reduced peak capacity contribution due to saturation nor do they capture the diversity benefit (positive or negative) of a mix of different types of VERs and ELRs.

In addition, recognizing that the ELCC values of different VERs and ELRs fluctuate by season and change from year to year depending on the portfolio resource mix, Idaho Power implemented seasonal resource specific ELCC saturation curves for VERs and ELRs in the AURORA LTCE model. The AURORA LTCE model cannot currently calculate the dynamic diversity benefit caused by a changing resource mix. To overcome this limitation, a feedback process was implemented between the AURORA LTCE model and the RCAT. As previously mentioned, select years in the planning horizon were chosen where the capacity position for an AURORA LTCE portfolio buildout was calculated using the RCAT. Once the capacity position was known, the PRM in the AURORA LTCE model was modified so that both models identified a similar capacity position. The feedback loop continued until both models converged.

More information on the LOLE methodology can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

Regulation Reserves

The 2020 VER Study provided the rules to define hourly reserves needed to reliably operate the system based on current and future quantities of solar and wind generation and load forecasted by season and time of day. The reserves are defined separately and incorporated into the model. The reserve rules applied in the 2023 IRP are approximations intended to generally reflect the amount of set-aside capacity needed to balance load and wind and solar production while maintaining system reliability.

For the 2023 IRP analysis, Idaho Power developed approximations for the VER study's regulating reserve rules. The approximations express the monthly up and down regulation reserve requirements as dynamic percentages of hourly load, wind production, and solar production. The approximations used for the IRP are given in Table 9.1. For each hour of the AURORA simulations, the dynamically determined regulating reserve is the sum of that calculated for each individual element.

Table 9.1 Regulation reserve requirements—percentage of hourly load MW, wind MW, and solar MW

	% of Load	% of Load	% of Wind	% of Wind	% of Solar	% of Solar
Month	**Load Up**	**Load Dn**	**Wind Up**	**Wind Dn**	**Solar Up**	**Solar Dn**
1	8.2%	1.7%	19.6%	19.6%	51.9%	57.6%
2	8.3%	1.6%	15.9%	21.2%	32.1%	39.3%
3	8.3%	1.7%	21.4%	22.1%	59.3%	59.3%
4	8.2%	1.7%	20.3%	26.0%	45.9%	50.6%
5	8.2%	1.6%	25.4%	34.5%	45.6%	53.7%
6	8.1%	1.6%	27.4%	21.7%	43.1%	29.3%
7	8.2%	1.4%	19.4%	22.0%	36.0%	24.6%
8	8.2%	1.5%	18.8%	23.8%	42.5%	31.9%
9	8.5%	1.8%	29.9%	29.9%	42.5%	40.5%
10	8.3%	1.6%	21.0%	31.8%	49.2%	51.4%
11	8.4%	1.8%	18.3%	29.2%	87.8%	71.8%
12	8.1%	1.6%	20.5%	39.3%	65.9%	73.3%

Inputs to AURORA Model

Calculated Reserve Amounts by Percentage of Corresponding Load/Generation

Portfolio Design Overview

Resource portfolios were developed under varying transmission options, future scenarios, and sensitivities. The LTCE model applies a capacity PRM hurdle and regulation reserve requirements, and then optimizes resource selections around those constraints to determine a least-cost, least-risk portfolio. Available future resources possess a wide range of operating, development, and environmental attributes. Impacts to system reliability and portfolio costs of these resources depend on future assumptions. Each portfolio consists of a combination of resources derived from the LTCE process that will enable Idaho Power to supply cost-effective electricity to customers over the 20-year planning period.

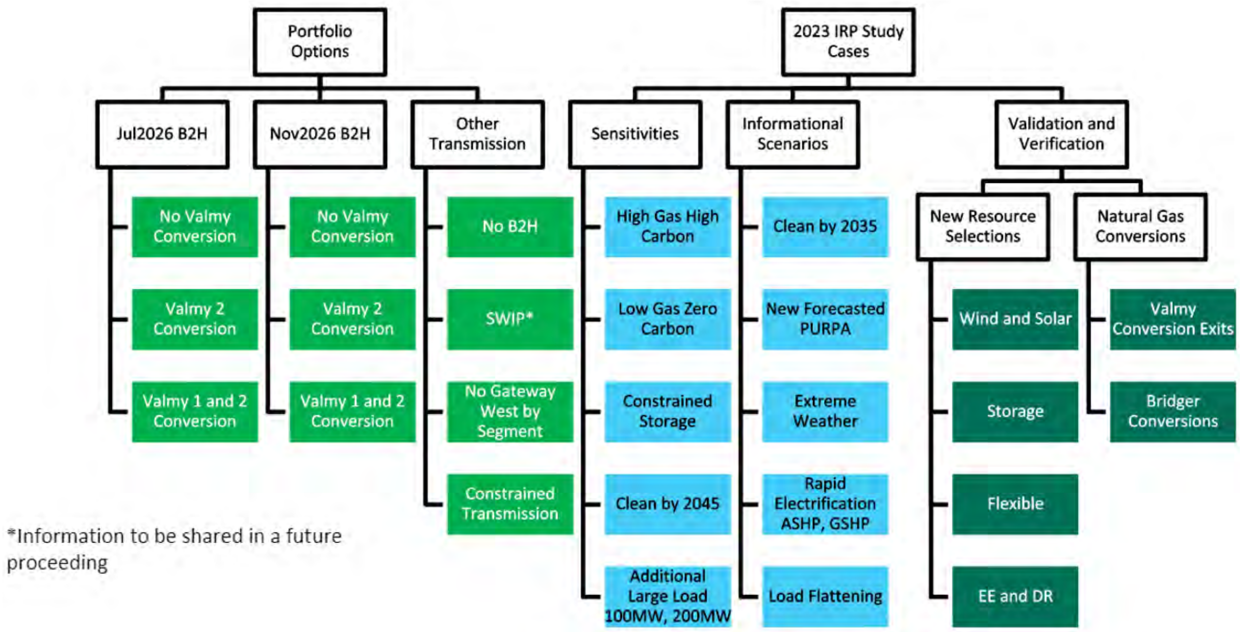


Figure 9.2 Analysis diagram

For the 2023 IRP, the company focused on key near-term decisions to ensure it identified an optimal solution specific to its customers. Figure 9.2 details the initial evaluation where the company compared AURORA-optimized portfolio options with varying transmission and natural gas conversion assumptions. Each of these portfolios were optimized by the AURORA LTCE model and validation and verification runs were performed to ensure portfolios were optimal and reliable.

Portfolio Naming Conventions

Planning conditions and forecasts, as explained throughout the 2023 IRP, are the most probable conditions and forecasts given the information available when the analysis is performed. These conditions and forecasts are identified Table 9.2.

Table 9.2. Planning conditions table

Condition	Description	Date
B2H	Online	July 2026
Gateway West Phase 1	Midpoint to Hemingway #2 500-kV Line Midpoint to Cedar Hill 500-kV Line Mayfield 500-kV substation 1,000 MW additional capacity	EOY 2028
Gateway West Phase 2	Cedar Hill to Hemingway 500-kV Line Cedar Hill 500-kV substation 1,000 MW additional capacity	EOY 2030
Gateway West Phase 3	Midpoint to Mayfield 500-kV Line 2,000 MW additional capacity	2040
Natural Gas Price Forecast	Long-term Platts Henry Hub	March 2023
Carbon Price Adder Forecast	California Energy Commission's Integrated Energy Policy Report Preliminary GHG Allowance Price Projections. Begins 2027.	December 2021
Load Forecast	Idaho Power Generated—70th Percentile	2023
Coal Price Forecast	Idaho Power Generated	2023
Hydro Conditions	Idaho Power Generated—50th Percentile	August 2022

Planning conditions are implied in each case. Deviations from those conditions are listed in each case's name. There are no base planning conditions for Valmy, as combinations of unit conversions are individually tested. The following two naming conventions are explained as examples. The case, "Valmy 1 & 2," includes natural gas conversions of both Valmy Unit 1 and Valmy Unit 2 as well as B2H in July of 2026, all three Gateway West phases as currently forecasted, and all other forecasts and conditions specified in the Planning Conditions Table (see Table 9.2). The case, "Nov2026 B2H Valmy 2," includes a natural gas conversion of Valmy Unit 2 and all the forecasts and conditions specified in the Planning Conditions Table with the exception that the B2H in service date is November 2026 instead of July 2026.

The list below entails the main cases analyzed for the 2023 IRP.

1. Valmy 1 & 2 (conversion of both units)
2. Valmy 2 (conversion of unit 2 only)
3. Without Valmy (without any unit conversions and Valmy unit 2 exit in 2026)
4. Nov2026 B2H Valmy 1 & 2 (conversion of both units)
5. Nov2026 B2H Valmy 2 (conversion of unit 2 only)
6. Nov2026 B2H Without Valmy (without any unit conversions and Valmy unit 2 exit in 2026)
7. Without B2H

8. Without Gateway West Phases (this portfolio excludes Midpoint–Hemingway #2 500-kV, Midpoint–Cedar Hill–Hemingway 500-kV, Midpoint–Mayfield 500-kV, Mayfield substation, and Cedar Hill substation)
9. Gateway West Phase 1 Only (Midpoint–Hemingway #2 500 kV, Midpoint–Cedar Hill 500-kV, and Mayfield substation)
10. Gateway West Phases 1 & 2 Only (Midpoint–Hemingway #2 500-kV and Midpoint–Cedar Hill–Hemingway 500-kV, Mayfield substation, and Cedar Hill substation)

The company then made relevant comparisons to determine the preferred path forward given specific conditions. Portfolio costs and stochastic results are detailed in Chapter 10.

The company developed additional portfolios to explore various scenarios, which are all described later in this section and are shown in Figure 9.2:

- Working with members of the IRPAC, the company developed future scenarios, in the blue boxes under “Sensitivities” and “Informational Scenarios” headings
- Several validation and verification tests, in dark green boxes under the “Validation and Verification” heading
- Various transmission robustness sensitivities and cost tests, in green boxes under the “Other Transmission” heading

Future Scenarios—Purpose: Risk Evaluation

It can be helpful to compare the resources selected in the Preferred Portfolio, developed under planning constraints and conditions, to resources selected in other possible scenarios. This is especially useful for near-term resources. The goal of the comparisons is to understand how resources would need to shift if various scenarios materialized.

Idaho Power identified scenarios to perform and then consulted with members of the IRPAC to generate additional scenarios of interest. Each is included in this section and the results can be found in Chapter 11.

The following is a description of the eleven future scenarios assessed in the 2023 IRP.

High Gas High Carbon

The High Gas High Carbon case adjusts the natural gas price and carbon adder price forecasts as shown in Table 9.3 below.

Table 9.3 High Gas High Carbon table

Variable	Designation	Date
Natural Gas Price Forecast	EIA Low Oil and Gas Supply	March 2023
Carbon Price Adder Forecast	Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990	February 2021

Low Gas Zero Carbon

The Low Gas Zero Carbon case adjusts the natural gas price and carbon adder price forecasts as shown in Table 9.4 below.

Table 9.4 Low Gas Zero Carbon table

Variable	Designation	Date
Natural Gas Price Forecast	EIA High Oil and Gas Supply	March 2023
Carbon Price Adder Forecast	Consistent Zero Dollars per Ton	

Constrained Storage

The Constrained Storage case examines what a resource portfolio would look like if the supply chain associated with minerals required for storage technologies was constrained, resulting in higher storage acquisition and construction prices. To model a constrained storage market, rather than use the declining price curves associated with storage indicated in the National Renewable Energy Laboratory's Annual Technology Baseline, storage prices were set to increase at the rate of inflation.

100% Clean by 2035

The 100% Clean by 2035 scenario assumes a legislative mandate to move toward 100% clean energy by the year 2035 throughout the WECC. The scenario carbon emission constraints start in 2024 with current emission levels and decrease to 0% by 2035. The same constraints were applied to the WECC unless the existing state constraints were more restrictive.

Technology breakthroughs, such as cost-effective, long-duration energy storage, nuclear energy, or hydrogen, will likely be required to meet this goal.

100% Clean by 2045

The 100% Clean by 2045 scenario assumes a legislative mandate to move toward 100% clean energy by the year 2045 throughout the WECC. The scenario carbon emission constraints start in 2024 with current emission levels and decrease to 20% by 2035 and 0% by 2045. The same constraints were applied to the WECC unless the existing state constraints were more restrictive.

Additional Large Load

Within the last few years, large industrial load interest has increased in the number of unique inquiries and projected total demand for electricity in Idaho. This large-load growth scenario examines how the resource portfolio might change if 100 and 200 MW of additional load were to be added to the system. These loads start in 2026 and ramp up to full load in three years. The load factor is similar to data center loads.

New Forecasted PURPA

For the 2023 IRP analysis, based on the desire to adequately plan for the future, QF wind facilities are not assumed to enter into replacement energy sales agreements with Idaho Power when their existing contracts expire. This is consistent with the assumptions in the 2021 IRP. If wind QF owners decide to enter into replacement agreements with Idaho Power when their existing agreements expire, Idaho Power will update its capacity positions in its planning at that time, and the updated position will be reflected in any subsequent resource procurement efforts. This approach allows sufficient resources to be selected by the model regardless of renewal status and allows the most up-to-date information to be considered in resource procurement. This assumption is for planning purposes and has no impact on the ability of QFs to decide whether or not to enter into a replacement agreement when their existing agreement expires.

The company and IRP stakeholders agreed there is value in modeling wind project renewals as well as a reasonable amount of new PURPA projects to observe how resource selection might be affected. Based on the policy conditions in Idaho that have resulted in no Idaho-based PURPA projects in recent years, the company did not consider it reasonable to include new PURPA contracts within base planning conditions. Rather, the company aligned on a CSPP scenario analysis with IRPAC. For this scenario, the CSPP wind renewal rate is set at 100% and new PURPA contracts are modeled at an additional 57 MW each year, 23 MW from wind and 32 MW from solar, starting in 2028. The 57 MW of forecasted PURPA resources was derived by identifying the average amount of new PURPA development the company experienced over the 10-year period from 2012 through 2021. This analysis showed an average of 57 MW of new PURPA resources developed per year.

Extreme Weather

The Extreme Weather scenario includes both an increased demand forecast associated with extreme temperature events and a variable supply of water from year to year. A 70th-percentile energy 95th-percentile peak load forecast was applied for Idaho Power's system. The variable water supply uses hydropower modeling results from the Planning Models. Rather than use the 50th-percentile of the distribution, as is applied in the planning cases, the variable water supply exhibits a mix of wet and dry cycles that have historically occurred in the hydrologic record. Using the variable water supply is intended to help determine the sensitivity of resource buildouts to hydrologic variability.

Rapid Electrification

The company forecasts moderate building and transportation electrification in all scenarios. The Rapid Electrification scenario was developed to determine what kind of adjustments would need to be made to the plan to accommodate a very rapid transition toward electrification.

This rapid transition includes increasing the electric vehicle forecast and the penetration of electric heat pumps for building heating and cooling. This aggressive forecast assumes over a million electric vehicles as well as adoption of an 80% penetration of heat pump technology at residences within the company's service area. These levels are blended into the load forecast over the next 20 years and do not factor in current economic consumer choice or the impact of existing legislation or incentives. The Rapid Electrification scenario is meant to serve as a high bookend on what is possible with the transition to electrification. As a bookend, the Rapid Electrification scenario is considered improbable.

Regarding building electrification, as a suggestion from our IRPAC, air-source heat pumps (ASHP) and ground-source heat pumps (GSHP) were modeled in separate portfolios. The substantial electrification costs and the difference in cost between heat pumps are not factored into this analysis.

Load Flattening

At the request of an IRPAC member, Idaho Power examined how resource needs would be met in a scenario where residential peak demands were shifted in time to non-peak hours. For this scenario, 10% of the peak each day was shifted to the time of day where the least load was used. This modification to load would require significant measures to accomplish; however, the aim of performing this sensitivity was not to identify how it would be done, but rather, what the resource portfolio would look like if it were accomplished.

Model Validation and Verification

The purpose of the Model Validation and Verification testing is to ensure the selection of the preferred portfolio is optimal and the model used in its selection is performing as expected. Model inputs also go through a validation and verification process. The optimization model validation and verification process includes a series of tests designed to show that the resources selected by the model are optimized correctly with a focus on the Action Plan Window (2024–2028). That is, by forcing the model to make different resource selections than the optimized output, verify that the forced resource selection is suboptimal. New to the 2023 IRP, the model was allowed to reoptimize the remaining selections. This process allows for robust testing of both key decisions like those concerning Bridger and Valmy as well as to test the selection of new resources. A high-level diagram of several tests performed is shown in Figure 9.3, followed by a discussion of these tests.

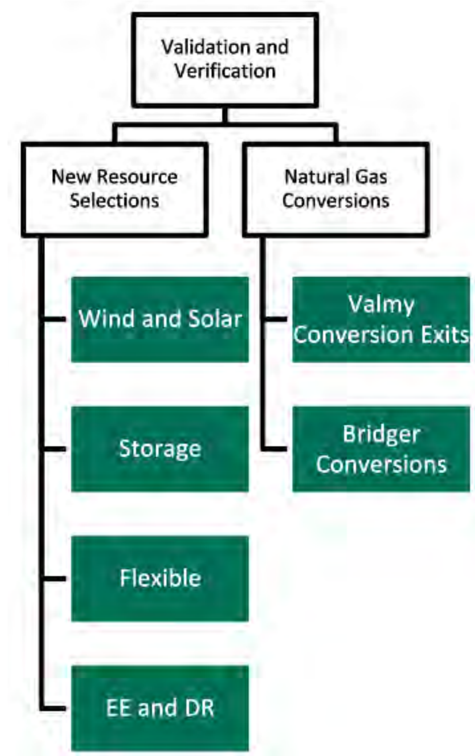


Figure 9.3 Model validation and verification tests

Bridger

Background—During the 2023 IRP cycle, Idaho Power was informed that PacifiCorp was analyzing the economics of converting Jim Bridger power plant units 3 and 4 from coal to natural gas. This validation and verification test is designed to test the Preferred Portfolio's selection for units 3 and 4.

Tests—To validate the conversion, or lack thereof, for units 3 and 4 to natural gas—whatever choice the model makes—the opposite will be forced into the model and then reoptimized around that selection. See Table 10.4.

Result—The decision made to convert Bridger units 3 and 4 to natural gas operation as selected in the Preferred Portfolio is the optimal decision based on the validation and verification tests. For details on the resources selected in the test results, see *Appendix C–Technical Report*.

Valmy

Background—During the 2023 IRP cycle, Idaho Power analyzed conversion options for Valmy units 1 and 2, which is detailed in Chapter 5. If either unit is converted, then the option also exists to exit from the unit prior to the technical end of life for the plant.

Test—Given the importance of the Valmy conversion or exit decision in the 2023 IRP, each of the conversion options for Valmy were individually tested in separate portfolios, with the remaining buildout allowed to optimize around those options.

Result—The decision to convert Valmy units 1 and 2 to natural gas operation as shown in the Preferred Portfolio is the optimal decision based on a comparison of the main case portfolios. For a cost comparison on each of the test results, see Table 10.2 and for a comparison of resources selected, see *Appendix C–Technical Report*.

New Resource Selections

Wind

Background—Wind resources are a major part of the Preferred Portfolio. Recent supply chain issues have increased the cost of wind production.

Test—Increase the cost of wind generation by 30% and determine how selected resources shift. See Table 10.4 for a cost comparison and the Long-Term Capacity Expansion Results section in *Appendix C—Technical Report* for the associated resource build.

Result—In an environment where wind costs are higher, the model can still select resources that keep the system reliable. The increased cost of wind increases the cost of the portfolio, as expected.

Battery Storage

Background—Battery storage resources are a major part of the Preferred Portfolio.

Test—Constrain the use of battery storage in the model by increasing the price, imitating a supply shortage. See Table 10.3 for a cost comparison and the Long-Term Capacity Expansion Results section in *Appendix C—Technical Report* for the associated resource build.

Result—The model is still able to select from resources that provide reliable capacity in the constrained storage scenario. Constraining storage results in a higher portfolio cost, as expected.

Nuclear

Background—Nuclear was not selected in the Preferred Portfolio.

Test—Force 100 MW of nuclear generation into the resource selection to offset the retirement of the Bridger units in 2038 and allow the model to optimize all other resources. See Table 10.4 for a cost comparison and the Long-Term Capacity Expansion Results section in *Appendix C—Technical Report* for the associated resource build.

Result—Forcing 100 MW of nuclear generation in 2038 increases costs, as expected.

Additional EE Bundles

Background—Additional EE bundles beyond the economic forecast were not selected in the Preferred Portfolio.

Test—Force six bundles of the lowest cost tier of EE measures in the Action Plan Window (2026–2028) with a combined nameplate of 98 MW. See Table 10.4 for a cost comparison and the Long-Term Capacity Expansion Results section in *Appendix C—Technical Report* for the associated resource build.

Result—Forcing EE measures into the Preferred Portfolio resource selection increases costs, as expected.

Demand Response

Background—No DR buckets were selected in the Preferred Portfolio.

Test—Force three bundles, one each to expand existing programs, add pricing programs, and add storage programs, into the Action Plan Window (2026-2028) with a combined nameplate of 60 MW. See Table 10.4 for a cost comparison and the Long-Term Capacity Expansion Results section in *Appendix C—Technical Report* for the associated resource build.

Result—Forcing EE measures into the Preferred Portfolio resource selection increases costs, as expected.

B2H Timing

Background—During the 2023 IRP cycle, Idaho Power analyzed the in-service date for B2H.

Test—Given the importance of B2H's in-service timing in the 2023 IRP, two timing scenarios were individually tested in separate portfolios: the planned July 2026 date and a conservative, post-summer, November 2026 date. The resource buildout was allowed to optimize around the B2H timing.

Result—The July 2026 date results in a least-cost portfolio, as expected. If necessary, Idaho Power can pivot to a November 2026 B2H in-service date but will see a moderate portfolio cost increase, as shown in Table 10.2. For details on the resources selected for a November 2026 B2H in-service date case, see *Appendix C–Technical Report*.

Natural Gas Price Variation Portfolios

Idaho Power tested portfolios under an additional high natural gas price forecast, EIA's Low Oil & Gas Supply forecast and low natural gas price forecast, EIA's High Oil & Gas Supply forecast. For more details and discussion on the natural gas price forecasts, see Chapter 8.

Carbon Price Variation Portfolios

Idaho Power developed portfolios primarily using the Planning Cast Carbon Cost forecast, and utilized both a Zero Carbon Costs and High Carbon Costs forecast for the Low Gas Zero Carbon scenario and the High Gas High Carbon scenario, respectively (see Chapter 10). These carbon price scenarios for the 2023 IRP are shown in Figure 9.4:

1. Zero Carbon Costs—assumes there will be no tax or fee on carbon emissions for those regions not already subject to a carbon cost.
2. Planning Carbon Cost—is based on the California Energy Commission's 2020 *Integrated Energy Policy Report Preliminary Green House Gas Allowance Price Projections*,[34] Low-price Scenario. The carbon cost forecast assumes a price of roughly $28 per ton beginning in 2027 and increases to over $83 per ton by the end of the IRP planning horizon. The price applies to those regions that have a carbon price less than this assumed price.
3. High Carbon Costs—is based on a federal interagency working group Technical Support Document: *Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*.[35] The carbon cost forecast assumes a price of approximately $65 per ton beginning in 2024 that increases to more than $132 per ton (nominal dollars) by the end of the IRP planning horizon. The price applies to those regions that have a carbon price less than this assumed price.

[34] 2020 California Energy Commission's *Integrated Energy Policy Report Preliminary Green House Gas Allowance Price Projections*, Low-price Scenario. Energy Assessment Division (December 2021).

[35] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Interagency Working Group and Social Cost of Greenhouse Gases, United States Government. February 2021. Accessed 9/1/2021 whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

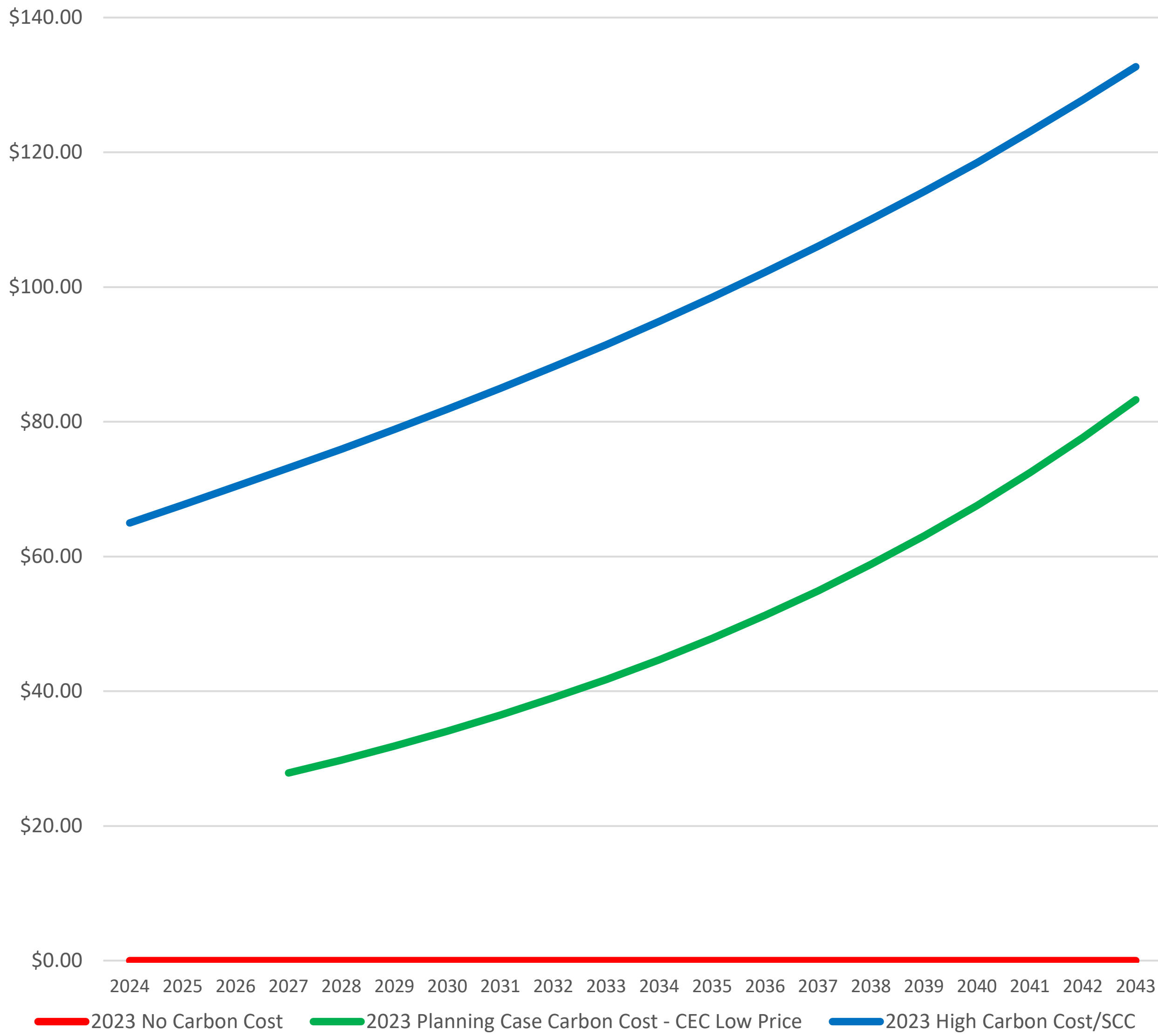


Figure 9.4 Carbon price forecast

10. MODELING ANALYSIS

Portfolio Cost Analysis and Results

Once the portfolios are created using the LTCE model, Idaho Power uses AURORA as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of zonal energy pricing and resource operation and emissions data. The portfolio cost analysis is a step that occurs *following* the development of the resource buildouts through the LTCE model.

The AURORA software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast zonal prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, and regional pool-pricing logic. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Portfolio costs are calculated as the NPV of the 20-year stream of annualized costs, fixed and variable, for each portfolio. Financial variables used in the analysis are shown in Table 10.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 10.1 Financial assumptions

Financial Variable	Value
Discount Rate (weighted average capital cost)	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.60%
Annual property tax rate (% of investment)	0.44%
B2H annual property tax rate (% of investment)	0.70%
Property tax escalation rate	3.00%
B2H property tax escalation rate	1.05%
Annual insurance premium (% of investment)	0.046%
B2H annual insurance premium (% of investment)	0.003%
Insurance escalation rate	5.00%
B2H insurance escalation rate	5.00%
AFUDC rate (annual)	7.50%

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 main case simulations, including different transmission and Valmy conversion assumptions, are shown in Table 10.2. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

Table 10.2 2023 IRP main cases

Portfolio	NPV years 2024–2043 ($ x 1,000,000)
Preferred Portfolio (Valmy 1 & 2)	$9,746
Valmy 2	$9,795
Without Valmy	$9,824
Nov2026 B2H Valmy 1 & 2	$9,767
Nov2026 B2H Valmy 2	$9,880
Nov2026 B2H Without Valmy	$10,192
Without B2H	$10,582
Without GWW Phases	$10,326
GWW Phase 1 Only	$10,263
GWW Phases 1 & 2 Only	$9,759

This comparison, as well as the stochastic risk analysis applied to select portfolios from this list (see the Stochastic Risk Analysis section of this chapter), indicate the Valmy 1 & 2 portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio.

The scenarios listed in Table 10.3 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Please note that these scenarios have varying conditions and constraints (see Chapter 10) associated with each specific future. Comparisons made between these scenario costs must take this into account. As an example, an alternative portfolio developed in a future with low natural gas prices and no carbon price adder (Low Gas Zero Carbon) would have a lower cost than the Preferred Portfolio (Valmy 1 & 2), but that lower cost would be attributable to both the direct influence on Idaho Power resources caused by the variable adjustments and the convolution of changes indirectly caused by their adjustments in the wider WECC.

Table 10.3 2023 IRP sensitivities

Portfolio	NPV years 2024–2043 ($ x 1,000,000)
Preferred Portfolio (Valmy 1 & 2)	$9,746
High Gas High Carbon	$12,520
Low Gas Zero Carbon	$8,594
Constrained Storage	$10,007
100% Clean by 2035	$11,351
100% Clean by 2045	$9,808
Additional Large Load (100 MW)	$10,236
Additional Large Load (200 MW)	$10,747
New Forecasted PURPA	$10,720
Extreme Weather	$10,211
Rapid Electrification (ASHP)	$12,271
Rapid Electrification (GSHP)	$11,175
Load Flattening	$10,663

The validation and verification tests are listed in Table 10.4. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the Near-Term 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 10.4 2023 IRP validation and verification tests

Portfolio	NPV years 2024–2043 ($ x 1,000,000)
Preferred Portfolio (Valmy 1 & 2)	$9,746
V&V Without Bridger 3 & 4	$9,945
V&V Valmy 1 & 2 Early Exit	$9,803
V&V Wind +30% Cost	$10,397
V&V Nuclear	$10,013
V&V Energy Efficiency	$10,042
V&V Demand Response	$9,816

Portfolio Emission Results

Figure 10.1 compares the full 20-year emissions of the company's 2023 IRP Preferred Portfolio contenders (main cases). In Figure 10.1, from left to right, the first six cases are the predicted planning conditions emissions associated with the Valmy conversion permutations in both the July and November B2H timing scenarios. The seventh case from the left is the Without B2H case emissions and the final three cases are the Gateway West sensitivities. Each of the six Valmy study cases show similar total emissions over the 20-year planning period with the percent difference between the max and min cases being less than 6%. Generally, the November B2H cases show marginally lower emissions over the 20-year planning horizon. The resources needed to replace the B2H capacity in the summer of 2026 slightly lower emissions but increase costs over the July B2H cases as seen in Table 10.2. Without B2H, the model builds new gas resources starting with a CCCT in 2029 which increases overall emissions.

The Gateway West sensitivities show that the access Gateway West provides to renewables significantly decreases portfolio emissions. Indeed, the case without any Gateway West phases has the greatest emissions of the preferred portfolio contenders.

The information presented in figures 1.4 and 3.2 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.

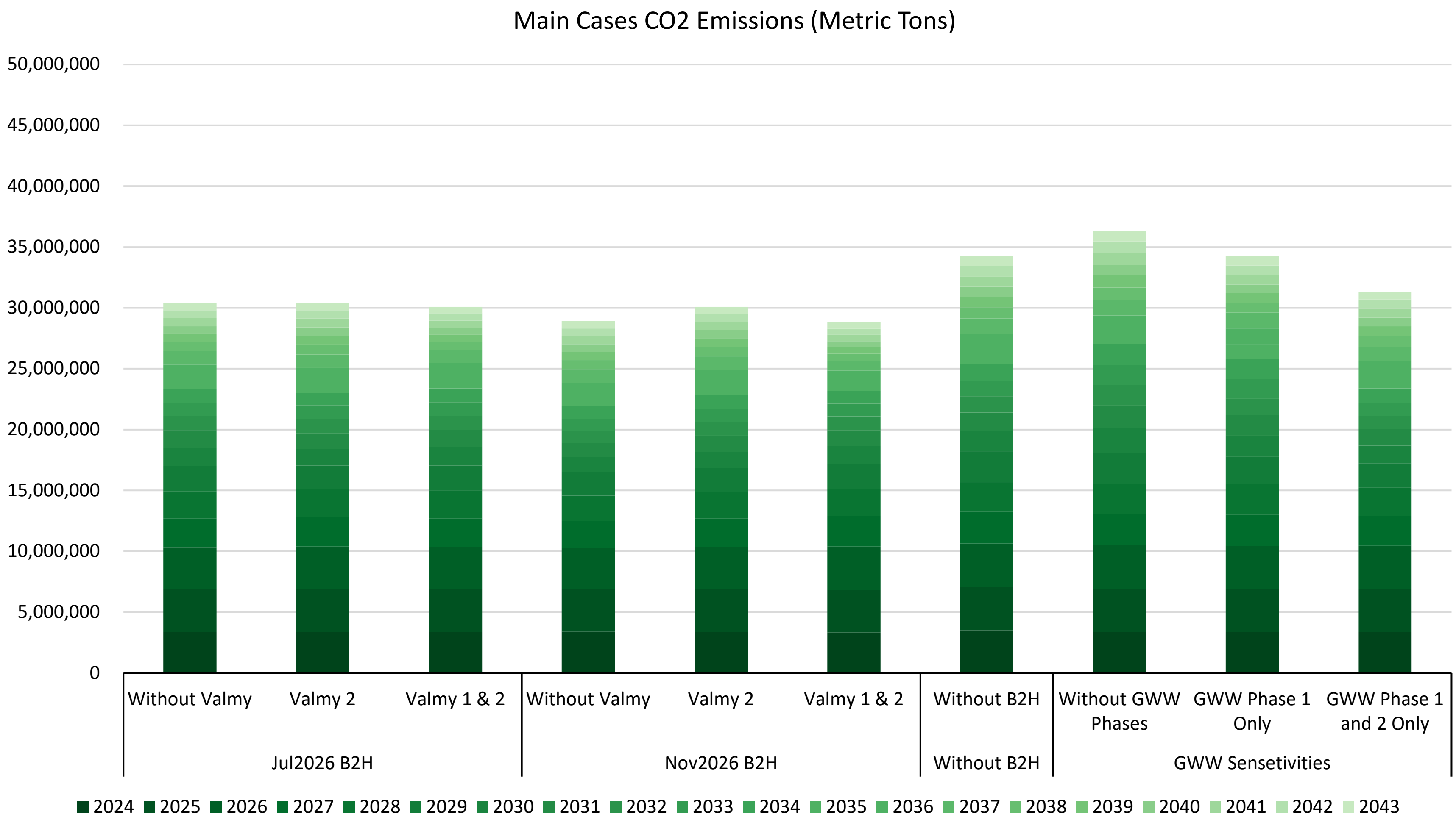


Figure 10.1 Estimated portfolio emissions from 2021–2040

In conclusion, the Preferred Portfolio (Valmy 1 & 2) strikes an appropriate balance of cost and risk while simultaneously reducing annual planning conditions emissions by more than 80% comparing 2024 to 2043. The Preferred Portfolio also lays a cost-effective foundation to build upon for further emissions reductions into the future. Idaho Power believes that technological advances will continue to occur to allow the company to reliably and cost-effectively achieve its goal of providing 100% clean energy by 2045.

For additional details on emissions for the 2023 IRP portfolios, please see the Portfolio Emissions Forecast section in *Appendix C—Technical Report.*

Qualitative Risk Analysis

Major Qualitative Risks

Supply Chain—For the last few years, various components and products have encountered supply chain issues. Supply chain issues limit the availability of resources and increase financial risk because low supply results in higher costs. Supply chain issues can also impact the ability to acquire resources when they are needed.

Fuel Supply—All generation resources require fuel to provide electricity. Different resource types have different fuel supply risks. Thermal resources like coal and natural gas rely on fuel supply infrastructure to produce and transport fuel by rail or pipeline and include mining or drilling facilities. New fuel supply chains like hydrogen or advanced nuclear reactors require new fuel which have yet to be developed at scale or a commercially viable price.

Fuel supply infrastructure has several risks when evaluating resources; it is susceptible to outages from weather, mechanical failures, labor unrest, etc. Fuel supply infrastructure can be limited in its existing availability to increase delivery of fuel to a geographic area that limits resources dependent on the capacity constrained infrastructure.

Fuel Price Volatility—Fuel prices can be volatile and impact a plant’s economics and usefulness to our customers both in the short and long term. Resources requiring purchased fuels like natural gas have a higher exposure to fuel price risk.

Market Price Volatility—Portfolios with resources that increase imports or exports heighten the exposure to a portfolio cost variability brought on by changes in market price and energy availability. Market price volatility is often dependent on regional fuel supply availability, weather, and fuel price risks. Resources, like wind and solar, that cannot respond to market price signals, expose the customer to higher short-term market price volatility.

Some resources can act as a hedge on market price volatility. Transmission can help reduce market volatility by allowing power to flow between regions during times of surplus or need. Storage resources can produce benefits from market volatility through arbitrage (charging at times when market prices are low and discharging when market prices are high).

Market Access—With many utilities including Idaho Power relying more on resources like wind and solar, the ability to access markets like the EIM becomes increasingly important. Lack of market access can cause considerable wholesale price fluctuations and high costs as well as present reliability concerns during times of need.

Siting and Permitting—All generation and transmission resources in the portfolios require siting and permitting for the resource to be developed. Siting and permitting processes are uncertain and time-consuming, increasing the risk of unsuccessful or prolonged resource acquisition resulting in an adverse impact on economic planning and operations. Resources that require air and water permits or that have large geographic footprints have a higher risk. All resources considered have some level of this qualitative risk. Portfolios with resources that are already through significant portions of the permitting process, like B2H and Gateway West, have a lower level of siting and permitting risk.

Emerging Technology—The potential for new or developing technologies to underperform relative to expectations (cost, operational characteristics, time to market, etc.). These risks can be difficult to predict and manage, as the technologies are often new and untested.

Partnerships—Idaho Power is a partner in generation facilities and is jointly permitting and siting transmission facilities in anticipation of partner participation in construction and ownership of these facilities. Coordinating partner need and timing of resource acquisition or retirement increases the risk of an Idaho Power timing or planning assumption not being met. Partner risk may adversely impact customers economically and adversely impact system reliability.

Federal and State Regulatory and Legislative Risks—There are many federal and state rules governing power supply and planning. The risk of future rules altering the economics of new resources or Idaho Power's electrical system composition is an important consideration. Examples include carbon emission limits or price adders, PURPA rules governing renewable resource contracts, tax incentives and subsidies for renewable generation or other environmental or political reasons. New or changed rules could have an adverse economic impact on customers and impact system reliability.

Each resource possesses a set of qualitative risks that, when combined over the study period, results in a unique and varied qualitative portfolio risk profile. Assessing a portfolio's aggregate risk profile is a subjective process weighing each component resource's characteristics against the potential bad outcomes for each resource and the portfolio of resources in aggregate. Idaho Power considered how qualitative risks affect each resource portfolio. Although the qualitative risk analysis performed is expansive, it is not exhaustive. For brevity, Idaho Power has limited the qualitative risk analysis to those risks that are typical within the power industry and accordingly does not consider exceedingly rare or hypothetical "black swan" events when performing qualitative risk analysis.

For purposes of risk assessment, each portfolio and risk is assigned a low-, medium-, or high-risk level. Consideration was given to both the likelihood and potential impact of each risk. The results of Idaho Power's qualitative risk assessment are presented in Table 10.5:

Table 10.5 Qualitative risk comparison

Portfolio	Energy Supply	Supply Chain	Market Volatility	Access to Markets	Siting and Permitting	Emerging Technology	Partnerships	State and Federal Policy
Valmy 1 & 2	Low	Low	Medium	Medium	Low	Medium	Medium	Medium
Without Valmy	Low	Medium	Medium	Medium	Medium	Medium	Low	Medium
Without B2H	Medium	Medium	High	High	High	Medium	Medium	High
Without GWW Phases	High	High	Medium	Medium	High	High	Medium	High
GWW Phase 1 Only	High	High	Medium	Medium	Medium	High	Medium	High

Stochastic Risk Analysis

The stochastic risk analysis assesses the effect on portfolio costs when select variables have values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and the degree to which they can affect the analysis results (i.e., portfolio costs).

The purpose of the analysis is to help understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations) and how the ranges for portfolios differ. It is used to identify the probabilities of various risks and the shape of those risks. To assess stochastic risk, the key drivers of natural gas prices, customer load, hydroelectric generation, and carbon prices are allowed to vary based on their historical variance. A full description of how these variables were modeled in the stochastic analysis can be found in the Stochastic Risk Analysis section of *Appendix C—Technical Report*.

In Figure 10.2 below, each line represents the likelihood of occurrence by NPV. Higher values on the line represent a higher probability of occurrence, with values near the horizontal axis representing improbable events. Values that occur toward the left have lower cost, while values toward the right have higher cost. As indicated by the peak of the graph being furthest left, the results of the stochastic analysis show that the Preferred Portfolio (Valmy 1 & 2) has the lowest cost given a range of natural gas prices, load forecasts, carbon prices, and hydroelectric generation levels.

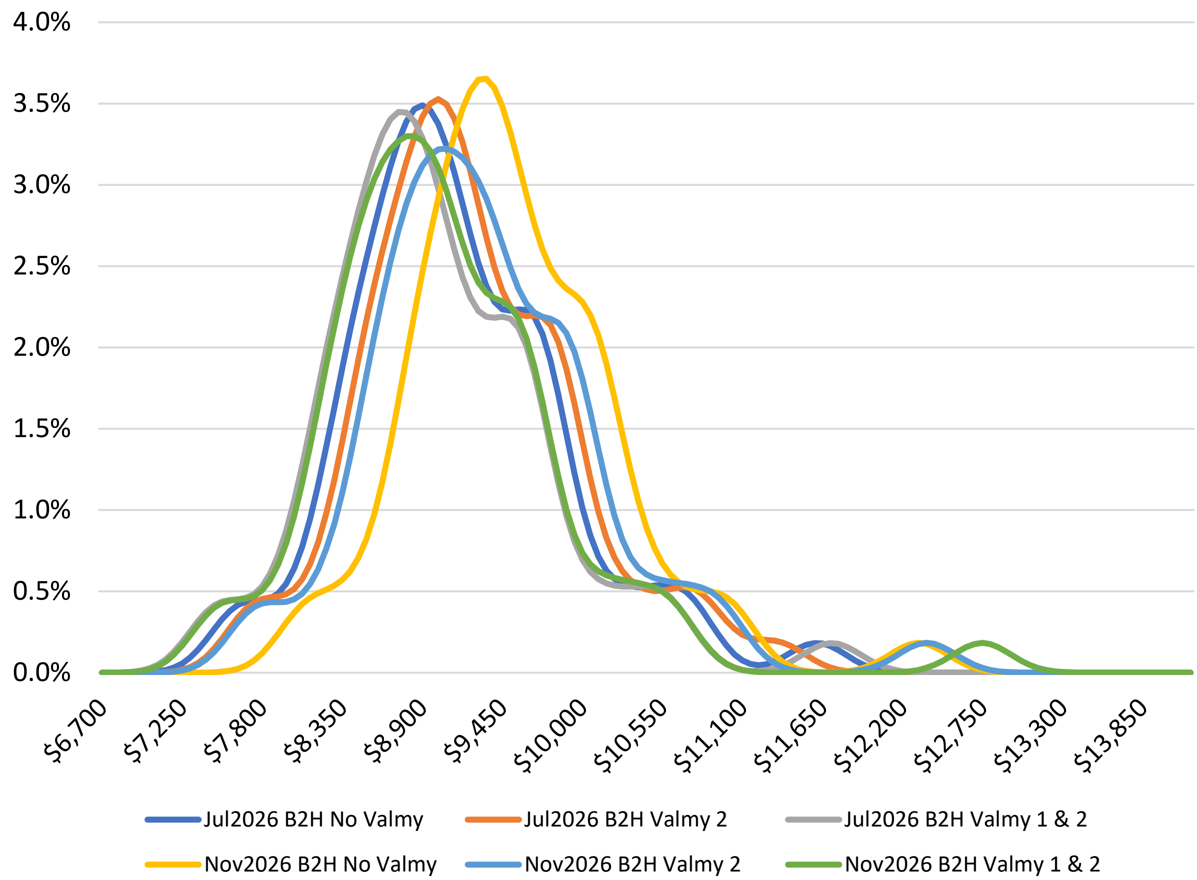


Figure 10.2 NPV stochastic probability kernel—Preferred Portfolio contenders (likelihood by NPV [$ x 1,000])

Loss of Load Expectation Based Reliability Evaluation of Portfolios

As a post-processing reliability evaluation, Idaho Power calculated the annual capacity position with the RCAT of select AURORA-produced portfolios to ensure the 20-year load and resource buildouts achieved the pre-determined reliability threshold.

The annual capacity position is obtained by averaging the resulting size of a perfect generating unit required to achieve a 0.1 event-days per year LOLE from each of the RCAT's six test years. If the LOLE-derived reliability evaluation found any select portfolio to have one or more years that resulted in a capacity shortfall, the company recalibrated the seasonal PRM points in AURORA and reran the LTCE which would again be tested for reliability.

The LOLE-derived evaluation is a minimum requirement for portfolios to be considered capacity reliable, however, there are other factors that drive resource selections and the resulting annual capacity positions. The AURORA LTCE model can select resources to address regulation reserves and energy requirements. Also, while VERs and ELRs can be added in more granular increments to meet the different AURORA LTCE requirements, other resources (i.e., coal-to-gas conversions and hydrogen units) must be selected at their identified nameplate capacity and at a specific time. Historically, Idaho Power has been capacity constrained, meaning peak capacity was the driving factor for acquiring resources. However, with the increased penetration of energy storage, energy needs and economics could drive resource additions.

An in-depth discussion of the reliability LOLE calculation process can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

Annual Capacity Positions of the Preferred Portfolio

The annual capacity positions for the Preferred Portfolio are provided in Table 10.6, which shows an annual position of capacity length for all years of the planning horizon meeting the company's reliability threshold.

Table 10.6 Preferred Portfolio annual capacity positions (MW)

Year	July 2026 B2H & Valmy 1 & 2 Gas Conversion	
2024	11	Length
2025	3	Length
2026	224	Length
2027	284	Length
2028	211	Length
2029	126	Length
2030	134	Length
2031	131	Length
2032	157	Length
2033	137	Length
2034	126	Length
2035	117	Length
2036	108	Length
2037	111	Length
2038	45	Length
2039	54	Length
2040	62	Length
2041	56	Length
2042	49	Length
2043	57	Length

All main cases were in a position of capacity length for all twenty years of the planning horizon.

11. PREFERRED PORTFOLIO AND NEAR-TERM ACTION PLAN

Preferred Portfolio

The 2023 IRP scenario analysis strategy focused on key near-term decisions and varying sensitivities to ensure that it had identified an optimal solution specific to Idaho Power and its customers. The company first identified main cases with resource buildouts driven by the timing of B2H, the inclusion of Gateway West, and assumptions related to Valmy unit conversions. Once portfolio buildouts were generated, to evaluate future cost risks, the company performed a cost analysis for the main cases by performing a stochastic analysis on the portfolios (see Chapter 10).

The company also evaluated the qualitative risks and evaluated the reliability of each of the main cases (see Chapter 10).

Using the Preferred Portfolio (Valmy 1 & 2), the company developed additional portfolios to do the following:

1. Evaluate risk associated with different futures and sensitivities (discussed later in this Chapter)
2. Perform validation and verification tests on the Preferred Portfolio

The Preferred Portfolio (Valmy 1 & 2) follows.

Table 11.1Preferred Portfolio resource selections

	Preferred Portfolio (MW)												
Year	Coal Exits	Gas	H2	Wind	Solar	4Hr	8Hr	100Hr	Trans.	Geo	DR	EE Forecast	EE Bundles
2024	-357	357	0	0	100	96	0	0	0	0	0	17	0
2025	0	0	0	0	200	227	0	0	0	0	0	18	0
2026	-134	261	0	0	100	0	0	0	Jul B2H	0	0	19	0
2027	0	0	0	400	375	5	0	0	0	0	0	20	0
2028	0	0	0	400	150	5	0	0	0	0	0	21	0
2029	0	0	0	400	0	5	0	0	GWW1	0	20	22	0
2030	-350	350	0	100	500	155	0	0	0	30	0	21	0
2031	0	0	0	400	400	5	0	0	GWW2	0	0	21	0
2032	0	0	0	100	100	205	0	0	0	0	0	20	0
2033	0	0	0	0	0	105	0	0	0	0	20	20	0
2034	0	0	0	0	0	5	0	0	0	0	40	19	0
2035	0	0	0	0	0	5	0	0	0	0	40	18	0
2036	0	0	0	0	0	5	0	0	0	0	40	17	0
2037	0	0	0	0	0	55	50	0	0	0	0	17	0
2038	0	-706	340	0	0	155	50	200	0	0	0	17	0
2039	0	0	0	0	0	5	50	0	0	0	0	15	0
2040	0	0	0	0	400	5	0	0	GWW3	0	0	14	0
2041	0	0	0	0	200	5	0	0	0	0	0	14	0
2042	0	0	0	0	200	55	0	0	0	0	0	14	0
2043	0	0	0	0	600	0	0	0	0	0	0	14	0
Sub Total	-841	261	340	1,800	3,325	1,103	150	200		30	160	360	0
Total	**6,888**												

The following items are included in Table 11.1:

- The addition of 3,325 MW of solar generation, including expected solar projects and solar to support the energy needs of large industrial customers.
- The conversion of Bridger units 1 and 2 (a combined 357 MW) is shown as a coal exit and a gas addition in 2024. These units are exited at the end of their useful life at the end of 2037.
- The conversion of Valmy units 1 and 2 (a combined 261 MW) occurs in 2026. Because Idaho Power exited coal operations at Valmy Unit 1, only Valmy Unit 2 is shown in that year as a coal exit. These units operate through the planning horizon.
- The conversion of Bridger units 3 and 4 (a combined 350 MW) occurs in 2030. These units are exited at the end of their useful life at the end of 2037.

- A total of 1,800 MW of economic wind projects are identified from 2027 through 2032. The quantity of wind and solar additions are dependent on the Gateway West transmission phases that are constructed.
- A total of 1,373 MW of energy storage, which includes the energy storage projects already contracted for completion in 2024 and 2025.
- In addition to meeting system resource needs, 80 MW of distribution-connected storage projects are intended to defer T&D investments.
- The B2H and Gateway West transmission lines (GWW1: Midpoint–Hemingway #2, Midpoint–Cedar Hill, and Mayfield substation; GWW2: Cedar Hill–Hemingway and Cedar Hill substation; and GWW 3: Midpoint–Mayfield) are represented in the Trans. column in 2026, 2029, 2031, and 2040, respectively.
- New to the 2023 IRP, hydrogen peaking units are identified. These units are identified in 2038 to facilitate the replacement of the Bridger units.
- A single 30 MW geothermal generation facility was selected in 2030.
- The combination of 160 MW of DR which represent both an expansion of the company's existing DR program and new programs.
- The energy efficiency (EE) Forecast column shows a total of 360 MW of cost-effective EE measures that will be added to Idaho Power's system to meet growing energy demand. These EE measures were identified in the EE Potential Assessment.

Preferred Portfolio Compared to Varying Future Scenarios

High Gas High Carbon

The following portfolio of resources was optimized for a future where gas prices throughout the WECC were driven high by perpetually low supply and carbon price adders were increased.

It should be noted that the conditions given in this scenario (high gas price and carbon adder forecasts) were applied to the entire WECC. Because every region was facing higher prices, low-cost, carbon-free resources were selected and the market was saturated with low price energy. Additional storage, including 250 MW of pumped hydro storage in 2031 (included in the “Storage” column of Table 11.2), is included in this portfolio as it is an effective way to store and then use the overabundance of renewable resources in the WECC. Though the portfolio shows the addition of some carbon emitting resources to meet needs, it should be noted that the emissions of this portfolio are lower than the emissions of the planning scenario, as expected.

Table 11.2 Preferred Portfolio—High Gas High Carbon comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										High Gas High Carbon (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	134	0	100	0	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	0	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	0	29	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	170	400	100	55	GWW1	0	31	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	686	200	0	55	0	0	32	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	400	600	455	GWW2	40	32	30
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	100	5	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	200	50	0	0	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	0	0	0	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	0	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	0	0	20	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	0	0	0	150	0	20	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-706	0	0	405	0	20	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	40	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	0	5	0	40	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	0	50	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	0	0	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	600	0	GWW3	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	640	1,800	2,525	1,563		180	401	60
Resources	**6,888**									**Resources**	**6,328**								
NPV Cost	**$9,746M**									**NPV Cost**	**$12,520M**								

*Geothermal Nuclear Biomass

Low Gas Zero Carbon

Similar to the prior scenario, the Low Gas Zero Carbon scenario includes adjustment to these variables throughout the entire WECC. In a scenario where natural gas prices are low and carbon emission adders are not present, this scenario shows that additional natural gas generation resources are cost effective. Emissions from this portfolio are higher than the emissions of the planning scenario, as expected.

This portfolio carries more risk in scenarios where the associated forecasts are higher.

Table 11.3 Preferred Portfolio—Low Gas Zero Carbon comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Low Gas Zero Carbon (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	0	0	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	200	150	5	0	0	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	400	300	5	GWW1	0	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	400	200	155	0	0	21	0
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	400	400	155	GWW2	0	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	200	155	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	55	0	0	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	5	0	20	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	5	0	40	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	40	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	340	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-366	0	0	105	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	55	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	0	5	0	40	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	500	0	GWW3	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	400	5	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	600	5	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	941	1,800	3,425	1,053		140	360	0
Resources	**6,888**									**Resources**	**6,878**								
NPV Cost	**$9,746M**									**NPV Cost**	**$8,594M**								

*Geothermal Nuclear Biomass

Constrained Storage

In the Constrained Storage run, in response to elevated storage costs throughout the WECC, natural gas generation and an additional 90 MW of geothermal replaced approximately 300 MW of storage. Also, while the total amount of incremental DR was the same in both portfolios, DR programs were identified early in the plan to assist the reduced amount of storage to meet system needs.

While Idaho Power expects storage technologies to continue to develop and for storage to become more affordable in the future, it is helpful to examine this assumption and understand which resources could be used in the place of cost-effective storage.

Table 11.4 Preferred Portfolio—Constrained Storage comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Constrained Storage (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	134	0	0	0	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	475	5	0	20	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	40	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	400	400	55	GWW1	40	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	200	0	205	0	0	21	0
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	-134	400	500	105	GWW2	20	21	30
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	100	5	0	20	20	30
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	105	0	0	20	30
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	5	0	0	19	30
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	55	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	55	0	0	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	55	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	55	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	55	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	0	55	0	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	0	5	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	200	5	GWW3	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	300	5	0	20	27	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	680	1,800	2425	1,158		160	373	120
Resources	**6,888**									**Resources**	**5,876**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,007M**								

*Geothermal Nuclear Biomass

100% Clean by 2035

With increasing urgency to move quickly to clean energy resources and at the request of the IRPAC, a 100% Clean by 2035 scenario was modeled. Model studies were set up to compare the Preferred Portfolio to a resource selection that adhered to a WECC wide 100% clean energy constraint by 2035.

Achieving a 100% clean portfolio by 2035 requires twice the storage as the Preferred Portfolio, including 500 MW of pumped storage in 2035 (included in the Storage column of Table 11.5). The pumped storage expands Idaho Power's hydro generation base and provides flexible energy when it is needed. The elevated energy costs in this scenario resulted in the selection of other high-cost resources including an additional 120 MW of geothermal generation and 150 MW of biomass. These resources supply the firm generation necessary to reliably serve system needs.

The portfolio cost for the 100% Clean by 2035 scenario does not include early decommissioning costs associated with Idaho Power's natural gas generation units.

Table 11.5 Preferred Portfolio—100% Clean by 2035 comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										100% Clean by 2035 (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	134	0	100	105	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	20	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	-175	0	400	0	255	GWW1	40	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-174	0	400	200	155	0	20	21	60
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	200	500	55	GWW2	0	21	30
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	200	205	0	0	20	60
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	100	205	0	0	20	60
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	205	0	40	19	30
2035	0	0	0	0	5	0	40	18	0	2035	0	-1,260	0	0	705	0	60	61	60
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	55	0	0	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	0	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	170	0	0	0	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	100	5	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	0	5	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	100	5	0	0	56	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	0	305	0	0	55	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	429	1,800	2,125	2,603		180	487	300
Resources	**6,888**									**Resources**	**6,993**								
NPV Cost	**$9,746M**									**NPV Cost**	**$11,351M**								

*Geothermal Nuclear Biomass

100% Clean by 2045

Idaho Power set a goal to provide 100% clean energy by 2045. A comparison of resources selected in the Preferred Portfolio compared to the resource selection that adheres to emission constraints that linearly lead to the goal is shown in the following table. The path to clean energy may not be linear and these assumptions were made to create a comparison scenario. The 100% Clean by 2045 scenario is strikingly similar to the Preferred Portfolio in the first several years, which illustrates how the current trajectory is in alignment with this goal. Early acquisition of cost-effective renewable resources is included in both portfolios.

Similar to other scenarios (e.g., 100% Clean by 2035 and High Gas High Carbon), the constraints that make this run unique were applied to the entire WECC because the economic and sustainability drivers that move Idaho Power towards this goal are likely to apply regionally. Other utilities and states are already making changes to their energy mix and moving this direction.

In this environment, cleaner, low-cost energy is available in the market. The optimized resource portfolio for this scenario takes advantage of this low-cost energy availability by increasing storage quantities earlier in the plan (compare storage builds in the years 2029 and 2030). This adjustment is more costly under planning conditions but is optimal for a rapidly transitioning clean future.

Table 11.6 Preferred Portfolio—100% Clean by 2045 comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										100% Clean by 2045 (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	134	0	100	0	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	20	21	0
2029	-175	0	400	0	5	GWW1	20	22	0	2029	-350	340	400	0	305	GWW1	40	22	0
2030	-174	350	100	500	155	0	0	21	30	2030	0	0	400	200	255	0	40	21	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	200	100	5	GWW2	20	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	300	5	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	400	55	0	0	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	105	0	0	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	-134	0	0	5	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	40	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-187	0	0	155	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	50	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	200	55	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	100	55	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	200	50	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	300	0	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	680	1,800	2,725	1,443		160	360	30
Resources	**6,888**									**Resources**	**6,357**								
NPV Cost	**$9,746M**									**NPV Cost**	**$9,808M**								

*Geothermal Nuclear Biomass

Additional Large Load

Idaho Power's industrial load is growing rapidly. The following two tables compare the Preferred Portfolio to a scenario where 100 MW and 200 MW of industrial load is added to the planning load forecast, respectively.

An additional 100 MW of load is supported by 160 MW of additional storage and a 170 MW natural gas generation unit in 2038. The larger 200 MW of additional load sees an increase of two gas units of the same size and 60 MW of geothermal generation. As expected, additional flexible generation resources facilitate increased base loads, especially during winter.

Table 11.7 Preferred Portfolio—Additional Large Load 100 MW comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Additional LL 100 MW (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	0	5	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	475	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	40	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	400	0	105	GWW1	40	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	300	300	105	0	0	21	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	300	0	5	GWW2	0	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	600	155	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	205	0	20	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	100	155	0	0	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	105	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	20	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-366	0	0	305	0	40	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	55	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	500	5	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	200	5	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	200	55	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	500	5	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	771	1,800	3,325	1,613		160	360	30
Resources	**6,888**									**Resources**	**7,218**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,236M**								

*Geothermal Nuclear Biomass

Table 11.8 Preferred Portfolio—Additional Large Load 200 MW comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Additional LL 200 MW (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	0	5	Jul B2H	20	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	475	5	0	20	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	105	0	20	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	400	300	255	GWW1	40	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	300	0	205	0	0	21	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	300	500	5	GWW2	0	21	30
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	200	5	0	40	20	30
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	105	0	20	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	55	0	20	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	50	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	0	0	0	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	155	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	100	5	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	400	5	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	100	55	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	200	100	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	941	1,800	2,725	1,448		180	360	90
Resources	**6,888**									**Resources**	**6,703**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,747M**								

*Geothermal Nuclear Biomass

New Forecasted PURPA

In response to requests from stakeholders to include a forecast of new PURPA QF development, in preparing the 2023 IRP, Idaho Power consulted with the IRPAC to develop a scenario that includes a forecast of future QF development. This scenario and forecast has the effect of reducing any deficits that might otherwise be identified, and therefore decreases the nameplate amount of capacity that would need to be acquired to meet increasing energy demand. Idaho Power applied this forecast of new QF development after the Action Plan window, starting in 2029, a choice made in consultation with IRPAC and with the understanding that earlier qualifying facility additions could distort resource selection in the critical near-term window and inaccurately reshape actions for regulatory acknowledgment. The forecast of future development is based on historical average nameplate capacity added over the years 2012 through 2021, and assumes in the future that 23 MW of wind is added per year, 32 MW of solar is added per year, and 2 MW of hydro—all in the form of PURPA qualifying facilities. The portfolio build comparison is below.

Additional PURPA contracts in this scenario result in a similar quantity of renewable resources compared to the Preferred Portfolio (4,705 MW and 5,125 MW, respectively). Flexible resources are also required in similar quantities for both scenarios. The New Forecasted PURPA scenario illustrates that PURPA contracts can help meet the need for renewable generation and that the resource quantities selected in the Preferred Portfolio are in general alignment with the resources selected in the New Forecasted PURPA scenario.

New and renewing PURPA resource rates were based on recent PURPA renewal prices.

Table 11.9 Preferred Portfolio—New Forecasted PURPA comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										New Forecasted PURPA (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	100	0	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	775	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	23	182	5	0	0	21	2
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	423	32	5	GWW1	0	22	2
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	423	232	5	0	0	21	2
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	423	32	155	GWW2	0	21	2
2032	0	0	100	100	205	0	0	20	0	2032	0	0	223	432	5	0	0	20	2
2033	0	0	0	0	105	0	20	20	0	2033	0	0	23	32	5	0	0	20	2
2034	0	0	0	0	5	0	40	19	0	2034	0	0	23	32	55	0	0	19	2
2035	0	0	0	0	5	0	40	18	0	2035	0	0	23	32	5	0	20	18	2
2036	0	0	0	0	5	0	40	17	0	2036	0	0	23	32	5	0	40	17	2
2037	0	0	0	0	105	0	0	17	0	2037	0	0	23	32	5	0	40	17	2
2038	0	-366	0	0	405	0	0	17	0	2038	0	-706	23	32	855	0	40	17	2
2039	0	0	0	0	55	0	0	15	0	2039	0	0	23	32	5	0	20	15	2
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	23	32	0	0	0	14	2
2041	0	0	0	200	5	0	0	14	0	2041	0	0	23	32	5	0	0	14	2
2042	0	0	0	200	55	0	0	14	0	2042	0	0	23	32	5	0	0	14	2
2043	0	0	0	600	0	0	0	14	0	2043	0	0	23	132	5	GWW3	0	14	2
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	261	2,168	2,537	1,453		160	360	32
Resources	**6,888**									**Resources**	**6,130**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,720M**								

*Geothermal Nuclear Biomass

Extreme Weather

In this scenario, the company modeled consistent high demand associated with extreme temperature events (95th percentile) and variable water supplies. These extremes are modeled for all years into the future.

Additional renewable resources and storage were identified to meet the requirements of the Extreme Weather scenario. The modeling adjustments impact resource selections starting in 2026 with 105 MW of additional storage. Other notable differences include an extra natural gas unit in 2029 and another hydrogen unit in 2038, both to meet the increased demand and compensate for low hydro years.

Table 11.10 Preferred Portfolio – Extreme Weather comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Extreme Weather (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	100	105	Jul B2H	20	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	5	0	40	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	105	0	20	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	170	400	0	0	GWW1	0	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	300	300	5	0	0	21	0
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	300	0	5	GWW2	0	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	300	5	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	400	205	0	0	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	5	0	0	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	5	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	20	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	0	0	0	155	0	20	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	205	0	20	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	0	55	0	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	0	5	0	40	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	200	55	GWW3	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	500	105	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	941	1,800	2,625	1,358		180	360	0
Resources	**6,888**									**Resources**	**6,423**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,211M**								

*Geothermal Nuclear Biomass

Rapid Electrification

A rapid path towards electrification—modeled with an aggressive electric vehicle forecast and an accelerated building heating and cooling transition—increases demand on the system year-round and throughout each day, but the increase in load during the winter has the most significant impacts on the electrical grid. The rapid electrification shift would require additional baseload generation units to reliably serve demand.

Using ASHPs for building electrification also requires an increased quantity of energy storage on the system, while GSHPs—at their significantly higher cost—help to mitigate that need.

The differences between the Preferred Portfolio and the Rapid Electrification scenarios can be seen in tables 11.11 and 11.12.

The comparison of the Preferred Portfolio and the Rapid Electrification scenario illustrates that course corrections, including the acquisition of additional flexible generation resources starting as early as 2029, can be made along the way to adjust to a steep ramp towards electrification.

Table 11.11 Preferred Portfolio—Rapid Electrification (ASHP) comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Rapid Electrification (ASHP) (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	100	5	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	55	0	20	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	205	0	40	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	300	400	300	5	GWW1	0	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	300	0	5	0	0	21	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	170	300	400	5	GWW2	0	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	300	355	0	0	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	705	0	0	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	340	0	0	5	0	20	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	55	0	20	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	0	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	340	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	155	0	20	17	30
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	155	0	20	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	400	200	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	400	0	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	300	5	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	400	155	0	20	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	1,921	1,800	3,425	2,403		160	360	60
Resources	**6,888**									**Resources**	**9,288**								
NPV Cost	**$9,746M**									**NPV Cost**	**$12,271M**								

*Geothermal Nuclear Biomass

Table 11.12 Preferred Portfolio—Rapid Electrification (GSHP) comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Rapid Electrification (GSHP) (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	0	5	Jul B2H	0	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	475	5	0	0	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	5	0	0	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	300	400	0	5	GWW1	0	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	200	400	5	0	0	21	0
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	400	0	5	GWW2	0	21	0
2032	0	0	100	100	205	0	0	20	0	2032	0	170	0	300	55	0	20	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	300	255	0	20	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	5	0	20	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	5	0	0	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	170	0	0	5	0	0	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	340	0	0	5	0	20	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	5	0	20	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	40	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	170	0	0	5	0	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	0	5	0	20	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	100	5	GWW3	20	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	100	55	0	0	14	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	1,921	1,800	2,125	763		180	360	0
Resources	**6,888**									**Resources**	**6,308**								
NPV Cost	**$9,746M**									**NPV Cost**	**$11,175M**								

*Geothermal Nuclear Biomass

Load Flattening

The purpose of the Load Flattening scenario was to determine how shifting load from peak demand times to times where demand was lowest would impact resource need and portfolio cost. This approach reduces peak load and increases system load factor by flattening the load curve.

As solar resources increase throughout the WECC in the plan, the cost of energy during summer daytime hours decrease. For the Load Flattening sensitivity, this had the undesired impact of shifting some load from high renewable output time periods to hours when flexible resources were required to meet demand. The shift required two additional flexible generation units (one in 2037 and one in 2038).

The Load Flattening scenario illustrates that to be effective at reducing costs, such a shift would need to adapt seasonally and annually to changing system needs and would need to be cost competitive with resources like battery storage that can serve a similar function.

Table 11.13 Preferred Portfolio—Load Flattening comparison table

Preferred Portfolio—Valmy 1 & 2 (MW)										Load Flattening (MW)									
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*	Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GNB*
2024	-357	357	0	100	96	0	0	17	0	2024	-357	357	0	100	96	0	0	17	0
2025	0	0	0	200	227	0	0	18	0	2025	0	0	0	200	227	0	0	18	0
2026	-134	261	0	100	0	Jul B2H	0	19	0	2026	-134	261	0	100	5	Jul B2H	20	19	0
2027	0	0	400	375	5	0	0	20	0	2027	0	0	400	375	5	0	20	20	0
2028	0	0	400	150	5	0	0	21	0	2028	0	0	400	150	105	0	40	21	0
2029	0	0	400	0	5	GWW1	20	22	0	2029	0	0	400	0	255	GWW1	0	22	0
2030	-350	350	100	500	155	0	0	21	30	2030	-350	350	300	300	205	0	0	21	30
2031	0	0	400	400	5	GWW2	0	21	0	2031	0	0	300	600	205	GWW2	0	21	30
2032	0	0	100	100	205	0	0	20	0	2032	0	0	0	100	55	0	20	20	0
2033	0	0	0	0	105	0	20	20	0	2033	0	0	0	0	5	0	20	20	0
2034	0	0	0	0	5	0	40	19	0	2034	0	0	0	0	55	0	0	19	0
2035	0	0	0	0	5	0	40	18	0	2035	0	0	0	0	5	0	20	18	0
2036	0	0	0	0	5	0	40	17	0	2036	0	0	0	0	5	0	20	17	0
2037	0	0	0	0	105	0	0	17	0	2037	0	170	0	0	5	0	0	17	0
2038	0	-366	0	0	405	0	0	17	0	2038	0	-196	0	0	155	0	0	17	0
2039	0	0	0	0	55	0	0	15	0	2039	0	0	0	0	5	0	0	15	0
2040	0	0	0	400	5	GWW3	0	14	0	2040	0	0	0	400	5	GWW3	0	14	0
2041	0	0	0	200	5	0	0	14	0	2041	0	0	0	200	5	0	0	14	0
2042	0	0	0	200	55	0	0	14	0	2042	0	0	0	500	5	0	0	14	0
2043	0	0	0	600	0	0	0	14	0	2043	0	0	0	300	5	0	20	27	0
Sub Total	-841	601	1,800	3,325	1,453		160	360	30	Sub Total	-841	941	1,800	3,325	1,413		180	373	60
Resources	**6,888**									**Resources**	**7,252**								
NPV Cost	**$9,746M**									**NPV Cost**	**$10,663M**								

*Geothermal Nuclear Biomass

Near-Term Action Plan (2024–2028)

The Near-Term Action Plan for the 2023 IRP reflects near-term actionable items of the Preferred Portfolio. The Near-Term Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to customers into the future. The current regional electric market, regulatory environment, pace of technological change and Idaho Power's goal of 100% clean energy by 2045 make the 2023 Near-Term Action Plan especially relevant.

The Near-Term Action Plan associated with the Preferred Portfolio is driven by its core resource actions through 2028. These core resource actions include some actions to which the company had committed prior to the development of the 2023 IRP and some that were identified as a result of the 2023 IRP analysis:

Actions Committed to Prior to the 2023 IRP–Not for Regulatory Acknowledgment

- 100 MW of solar and 96 MW of four-hour storage added in 2024 (resources selected through Requests for Proposals [RFP])
- Conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024 (conversions scheduled to occur by summer of 2024)
- 95 MW of additional cost-effective EE between 2024 and 2028 (added EE identified in Idaho Power's 2022 energy efficiency potential study)
- 200 MW of solar added in 2025 (executed contract for clean energy customer resource)
- 227 MW of four-hour storage added in 2025 (resources selected from the 2024 RFP)

2023 IRP Decisions for Acknowledgment

- B2H online by summer 2026
- Continue exploring Idaho Power's potential participation in the SWIP-N project
- Install cost-effective distribution-connected storage from 2025 through 2028
- Convert Valmy units 1 and 2 from coal to natural gas by summer 2026
- If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources, in 2026 through 2028 (inclusive of 625 MW of forecast CEYW resources)
- Explore a 5 MW long-duration storage pilot project
- Include 14 MW of capacity associated with the WRAP

- Midpoint–Hemingway #2 500-kV, Midpoint–Cedar Hill 500-kV, and Mayfield 500-kV substation (Gateway West Phase 1) online by end-of-year 2028

The Near-Term Action Plan is the result of the above resource actions and portfolio attributes, which are discussed in the following sections. Further discussion of the core resource actions and attributes of the Preferred Portfolio is included in this chapter. A chronological listing of the near-term actions follows in Table 11.14.

Table 11.14 Near-Term Action Plan (2024–2028)

Year	Action
2023–2024	Continue exploring potential participation in the SWIP-N project
2024	Add 100 MW of solar and 96 MW of four-hour storage
Summer 2024	Convert Bridger units 1 and 2 from coal to natural gas
2024–2028	Add 95 MW of cost-effective EE between 2024 and 2028
2024–2028	Explore a 5 MW long-duration storage pilot project
2025	Add 200 MW of solar
2025	Add 227 MW of four-hour storage
2025–2028	Install cost effective distribution-connected storage
Summer 2026	Bring B2H online
Summer 2026	Convert Valmy units 1 and 2 from coal to natural gas
2026–2028	If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources
2027	Include 14 MW of capacity associated with the Western Resource Adequacy Program
2028	Bring the first phase of Gateway West online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation)

Resource Procurement

Idaho Power's capacity shortfall identified for 2026 through 2028 will require incremental generating capacity. Idaho Power issued an all-source 2026 RFP in spring 2023. This RFP is for resources to come online by summer 2026 or summer 2027. The all-source 2026 RFP is ongoing. An additional RFP may be necessary to acquire resources for summer of 2028. For more information on Idaho Power RFPs visit idahopower.com/about-us/doing-business-with-us/request-for-resources/.

Annual Capacity Positions Replace Traditional Load and Resource Balance

To better align with and represent the probabilistic reliability analyses used in the 2023 IRP, the company provides annual capacity positions in place of the deterministic load and resource balance used in previous IRP cycles. The annual capacity position is a better indication of resource reliability.

The annual capacity position used in the 2023 IRP (Table 11.15) incorporates the most up-to-date resource and load inputs. The resulting capacity deficiency (approximately 22 MW in 2026, 44 MW in 2027, and 182 MW in 2028) clearly demonstrates capacity needs.

Table 11.15 Pre and post Preferred Portfolio annual capacity positions

Annual Capacity Position (MW)				
Year	Existing & Contracted Resource Only		Add Preferred Portfolio Resources	
2024	11	Length	11	Length
2025	3	Length	3	Length
2026	(22)	Shortfall	224	Length
2027	(44)	Shortfall	284	Length
2028	(182)	Shortfall	211	Length
2029	(324)	Shortfall	126	Length
2030	(693)	Shortfall	134	Length
2031	(767)	Shortfall	131	Length
2032	(796)	Shortfall	157	Length
2033	(869)	Shortfall	137	Length
2034	(891)	Shortfall	126	Length
2035	(913)	Shortfall	117	Length
2036	(938)	Shortfall	108	Length
2037	(1006)	Shortfall	111	Length
2038	(1317)	Shortfall	45	Length
2039	(1347)	Shortfall	54	Length
2040	(1377)	Shortfall	62	Length
2041	(1415)	Shortfall	56	Length
2042	(1456)	Shortfall	49	Length
2043	(1568)	Shortfall	57	Length

The first month of deficiency was determined to be the first month that exceeded a 0.0083 event-days per year LOLE (or 0.1 divided by 12) on the first year of capacity deficiency (2026). For this IRP, the first month over that threshold was July 2026, as shown in Figure 11.1.

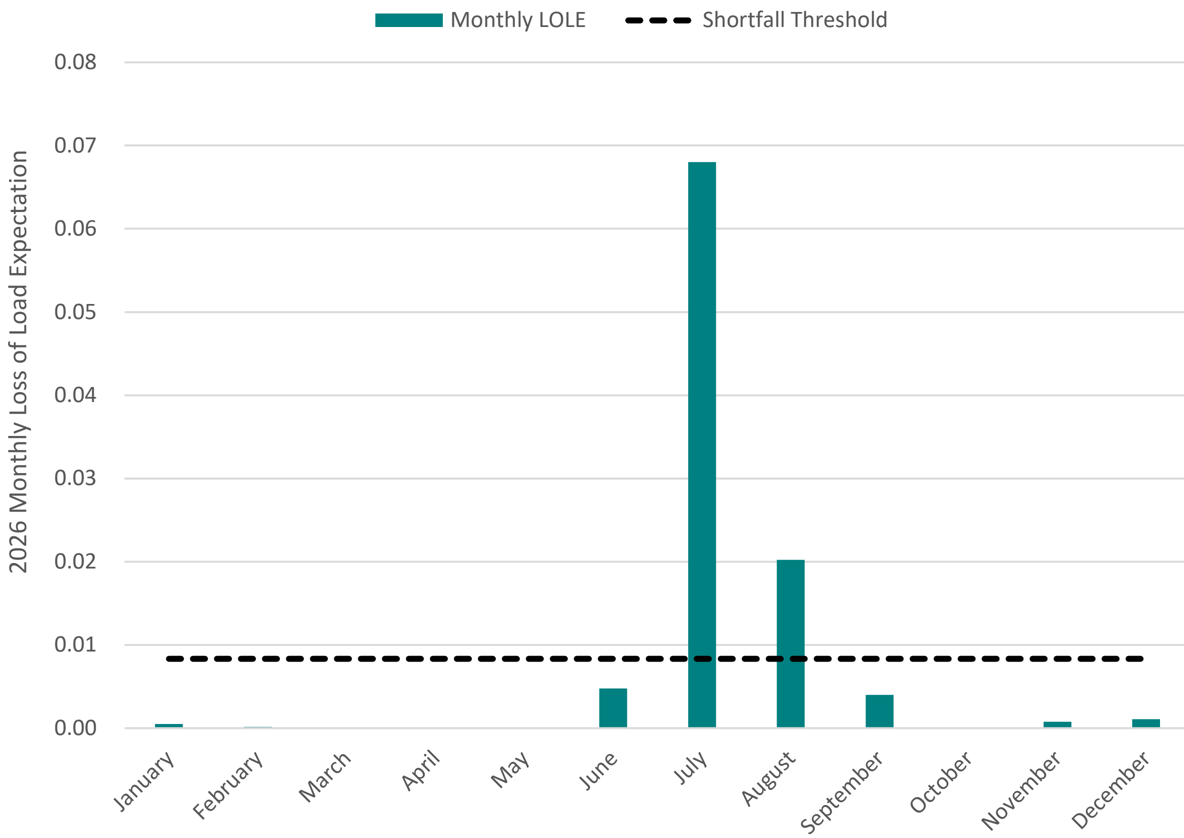


Figure 11.1 First month of capacity shortfall

An in-depth discussion of the reliability LOLE calculation process can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

2025 IRP Filing Schedule

The 2025 IRP will be filed in June 2025. Including the extended timelines for the 2021 IRP and the 2023 IRP, both were completed approximately 21 months from the previous IRP filing. The same timeframe for the 2025 IRP will result in an on-time filing. The following associated tasks will be completed between the 2023 IRP filing and the 2025 IRP filing:

- Model inputs will be collected prior to IRPAC meetings in the first 10 months.
- Between 8 and 12 IRPAC meetings will be conducted in 8–12 months.
- The analysis will begin coincident with the last three to four IRPAC meetings.
- The report will be drafted concurrent with the IRPAC meetings and analysis.
- A public review will be scheduled prior to the IRP filing.
- The IRP will be filed in June 2025.

Conclusion

The 2023 IRP provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. The B2H transmission line continues in the 2023 IRP analysis to be a top performing resource alternative, providing Idaho Power access to affordable and clean energy in the Pacific Northwest wholesale electric market. From a regional perspective, the B2H transmission line, and high-voltage transmission in general, is critical to achieving cost-effective clean energy objectives, including Idaho Power's goal of 100% clean energy by 2045.

Idaho Power linemen install upgrades.

Idaho Power prepares an IRP every two years. The next plan will be filed in 2025. The energy industry is expected to continue undergoing substantial transformation over the coming years, and new challenges and questions will be encountered in the 2025 IRP. Idaho Power will continue to monitor trends in the energy industry and adjust as necessary.