IDAHO POWER®
An IDACORP Company

DECEMBER • 2021

A VIEW
FROM ABOVE

IRP
INTEGRATED RESOURCE PLAN

SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

GLOSSARY OF ACRONYMS

A/C—Air Conditioning

AC—Alternating Current

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

AgI—Silver Iodide

akW—Average Kilowatt

aMW—Average Megawatt

ATC—Available Transfer Capacity

B2H—Boardman to Hemingway

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CADSWES—Center for Advanced Decision Support for Water and Environmental Systems

CAISO—California Independent System Operator

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CO_2—Carbon Dioxide

CPCN—Certificate of Public Convenience and Necessity

CSPP—Cogeneration and Small-Power Producers

CWA—*Clean Water Act of 1972*

DC—Direct Current

DEQ—Department of Environmental Quality

DER—Distributed Energy Resources

DOE—Department of Energy

DPO—Draft Proposed Order

DSM—Demand-Side Management

DSP—Distribution System Planning

E3—Energy and Environmental Economics, Inc.

EE—Energy Efficiency

EFOR— Effective Forced Outage Rate

EFSC—Energy Facility Siting Council

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

ELCC—Effective Load Carrying Capability

EPA—Environmental Protection Agency
ESA—*Endangered Species Act of 1973*
ESPA—Eastern Snake River Plain Aquifer
ESPAM—Enhanced Snake Plain Aquifer Model
FCRPS—Federal Columbia River Power System
FERC—Federal Energy Regulatory Commission
FPI—Fire Potential Index
FPA—*Federal Power Act of 1920*
GBT—Great Basin Transmission
GHG—Greenhouse Gas
GWMA—Ground Water Management Area
HB—House Bill
HCC—Hells Canyon Complex
HGHC—High Gas High Carbon
HRSG—Heat Recovery Steam Generator
IDWR—Idaho Department of Water Resources
IEPR—Integrated Energy Policy Report
IGCC—Integrated Gasification Combined Cycle
INL—Idaho National Laboratory
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
ISEA—Idaho Strategic Energy Alliance
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
LOLP—Loss of Load Probability
LTCE—Long-Term Capacity Expansion
m^2—Square Meters
MMBtu—Million British Thermal Units
MSA—Metropolitan Statistical Area
MW—Megawatt

MWh—Megawatt-Hour
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NOx—Nitrogen Oxide
NPV—Net Present Value
NRC—Nuclear Regulatory Commission
NREL—National Renewable Energy Laboratory
NWPCC—Northwest Power and Conservation Council
NYMEX—New York Mercantile Exchange
O&M—Operation and Maintenance
OATT—Open-Access Transmission Tariff
ODOE—Oregon Department of Energy
OPUC—Oregon Public Utility Commission
pASC—Preliminary Application for Site Certificate
PAC—PacifiCorp
PCA—Power Cost Adjustment
PGE—Portland General Electric
PM&E—Protection, Mitigation, and Enhancement
PPA—Power Purchase Agreement
PTC—Production Tax Credit
PURPA—*Public Utility Regulatory Policies Act of 1978*
PV—Photovoltaic
QF—Qualifying Facility
REC—Renewable Energy Certificate
RFP—Request for Proposal
RICE—Reciprocating Internal Combustion Engine
ROD—Record of Decision
ROR—Run-of-River
RPS—Renewable Portfolio Standard
RTF—Regional Technical Forum
SB—Senate Bill
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SMR—Small Modular Reactor
SO_2—Sulfur Dioxide
SRBA—Snake River Basin Adjudication
SWIP—South West Intertie Project
T&D—Transmission and Distribution

TRC—Total Resource Cost

UCT—Utility Cost Test

USBR—United States Bureau of Reclamation

USFS—United States Forest Service

VER—Variable Energy Resources

WECC—Western Electricity Coordinating Council

IRP REPORT:

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

Introduction

The 2021 Integrated Resource Plan (IRP) is Idaho Power's 15th resource plan prepared in accordance with regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC).

The 2021 IRP evaluates the 20-year planning period from 2021 through 2040. During this period, Idaho Power's load is forecasted to grow by 1.4% per year for both average energy demand and peak-hour demand. Total average annual customers are expected to increase from just over 600,000 in 2021 to 847,000 by 2040. To meet this growing demand, the 20-year plan includes the addition of 3,790 megawatts (MW) of new non-carbon emitting resources consisting of wind, solar, and storage technologies, the addition of the Boardman to Hemingway (B2H) transmission line, and a variety of demand-side management resource additions totaling 540 MW.

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 2021 IRP. Under AURORA's Long-Term Capacity Expansion (LTCE) modeling approach, resources are selected from a variety of supply- and demand-side resource options to develop portfolios that are least-cost for the given alternative future scenarios with the objective of meeting a 15.5% planning margin and regulating reserve requirements associated with balancing load, wind, and solar-plant output. The model can also select to exit 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.

The 2021 IRP reflects significant modeling improvements over past resource planning processes. Idaho Power used AURORA's LTCE platform with varied success in the 2019 IRP. In the 2019 IRP, the LTCE was able to optimize for the entire western interconnection; however, it was incapable of simultaneously optimizing for Idaho Power's service area and the western interconnection. The company therefore went through a manual optimization process to determine an Idaho Power Preferred Portfolio. Between the 2019 and 2021 IRPs, the company worked with Energy Exemplar to add functionality that allows for co-optimization between the western interconnection and Idaho Power specifically. This ability to co-optimize allowed for a more streamlined modeling process. As a result, the resource portfolios developed in the 2021 IRP were optimized entirely within the LTCE platform, without manual adjustments, specific to Idaho Power's balancing area.

To ensure the AURORA-produced portfolios provide customers affordable energy, Idaho Power employed verification tests to validate the most economic portfolio under numerous variations of resources and timing.

To verify the AURORA-produced portfolios could meet Idaho Power's reliability requirements, Idaho Power leveraged a new method of measuring each portfolio's reliability through the calculation of a portfolio Loss of Load Expectation (LOLE). For those portfolios that did not achieve the minimum reliability threshold, an additional reliability resource requirement was added to the portfolio cost.

Details about the validation and verification process can be found in Chapter 9, and a discussion of the results can be found in Chapter 10. 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 the AURORA-developed portfolios, Idaho Power conducted a financial analysis of costs and benefits. The financial costs and benefits include:

- Construction costs
- Fuel costs
- Operations and Maintenance (O&M) costs
- Transmission upgrade costs associated with interconnecting new resource options
- Natural gas pipeline reservation or 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

As part of the 2021 IRP analysis, the company conducted economic sensitivity analyses on several resources, including the B2H transmission line project, which has been included in IRPs since 2009.

Further discussion of the treatment of B2H in the 2021 IRP capacity expansion modeling is provided in chapters 7, 9, and 10.

Additionally, to enhance the risk evaluation within the 2021 IRP, the company worked with the IRP Advisory Council (IRPAC) to develop four unique future scenarios to test. The company ultimately used these scenarios to determine whether the decisions being made within the

Action Plan window (2021–2027) are robust and reliable across different futures. The four future scenarios are:

- Rapid Electrification
- Climate Change
- 100% Clean by 2035
- 100% Clean by 2045

Portfolio Analysis Overview

For the 2021 IRP, Idaho Power identified several key features on which to build out resource portfolios. These features were preset in AURORA and then the LTCE model was used to optimize portfolios based on these set features. These key features are as follows:

- With and without the B2H project
- With and without portions of the Gateway West project
- Allowing the model to choose from specified Bridger Coal Plant exit date and natural gas conversion date assumptions to determine Idaho Power's system economics
- Aligning with PacifiCorp's (PAC) Bridger Coal Plant exit date and natural gas conversion date assumptions

These portfolios were compared against each other using various natural gas price forecasts (referred to as "planning" and "high") and carbon adder price forecasts ("zero," "planning," and "high"). The planning case for natural gas and carbon adder price forecasts represent Idaho Power's assessment of the most likely future.

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 Action Plan window of the Preferred Portfolio were compared to optimal resources selected for four future scenarios to determine the changes that would need to be made in each of those scenarios: Rapid Electrification, Climate Change, 100% Clean by 2035, and 100% Clean by 2045.
- Both low and high Cogeneration and Small Power Producers (CSPP) wind renewal assumptions were tested to determine the impact on the resources selected within the Action Plan window.
- A sensitivity was evaluated to test the cost-effectiveness of the Southwest Intertie Project (SWIP) North transmission project—a potential future partnership opportunity.

- Validation and verification studies were performed to test coal exit dates, Bridger unit natural gas conversions, and both supply-side and demand-side resources.
- Various tests and sensitivities were performed on the B2H project capacity, cost, and timing assumptions.

Table 1.1 shows the resource additions and coal exits that characterize Idaho Power's 2021 IRP Preferred Portfolio over the 20-year planning period.

Table 1.1 Preferred Portfolio additions and coal exits (MW)

	Base B2H (MW)								
Year	Gas	Wind	Solar	Storage	Trans.	DR	Coal Exits	EE Forecast	EE Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	105	0	20	-308	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	55	0	0	-175	27	0
2029	0	0	100	255	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	700	1,405	1,685	500	400	-841	428	12
Total	**4,289**								

Preferred Portfolio Changes from the 2019 IRP

Compared to the 2019 IRP, the Preferred Portfolio of the 2021 IRP incorporates positive changes towards clean, low-cost resources, as well as an increased focus on system reliability. Table 1.2 highlights these changes.

Table 1.2 2021 IRP comparison to the 2019 IRP

2019 IRP Preferred Portfolio	2021 IRP Preferred Portfolio
The last coal generation unit exit was planned in 2030.	The last coal generation unit exit is planned in 2028 (two years earlier).
The B2H transmission line was identified as a least-cost resource.	B2H continues to be a least-cost resource.
411 MW of new natural-gas generation was identified in the plan.	The plan includes a conversion of Bridger coal units 1 and 2 to natural gas operation with a 2034 exit date.
400 MW of solar was included.	700 MW of wind plus 1,405 MW of solar are included.
80 MW of battery storage was identified.	1,685 MW of battery storage is included.
45 MW of additional Demand Response (DR) was selected.	In addition to updating existing DR programs to be more effective during high-risk hours, an additional 100 MW of DR is included.
No energy efficiency bundles were included beyond the measures determined to be cost-effective in the Potential Assessment.	In addition to the measures identified in the Potential Assessment, 12 MW of additional energy efficiency measures was selected, for a total of 440 MW of planned energy efficiency.

Importantly, the 2021 IRP was assessed on the same principles of minimizing cost and risk (the least-cost, least-risk portfolio) as the 2019 IRP. The outcome, however, is notably different between the two IRPs. The 2021 Preferred Portfolio includes significant amounts of clean resources—700 MW of wind, 1,405 MW of solar, and 1,685 MW of battery storage (some of it paired with solar). In contrast, the 2019 IRP Preferred Portfolio included no wind resources, roughly two-thirds less solar, and only a fraction of the amount of battery storage than was identified in the 2021 IRP.

The 2021 IRP also reflects different amounts and timing of thermal resources, with the company exiting all coal by 2028—two years earlier than the final coal exit date in the 2019 IRP. With respect to natural gas, the only gas additions in the 2021 IRP stem from the conversion of Bridger coal units 1 and 2 to natural gas resources, compared to 411 MW of new gas added in the 2019 IRP.

DR has also grown considerably in the 2021 IRP, with 100 MW included in the Preferred Portfolio compared to 45 MW in the 2019 IRP. Finally, energy efficiency expanded in the 2021 IRP, with 12 MW of additional energy efficiency selected—for a total of 440 MW of energy efficiency planned across the 20-year planning horizon.

Action Plan (2021–2027)

The Action Plan for the 2021 IRP reflects near-term actionable items of the Preferred Portfolio. The Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to our 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 2021 Action Plan especially relevant.

The Action Plan associated with the Preferred Portfolio is driven by its core resource actions through 2027. These core resource actions include:

- 120 MW of added solar photovoltaic (PV) capacity in 2022
- Conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024 with a 2034 exit date
- Seek to acquire significant capacity and energy resources to meet demand growth needs in 2023 through 2027
- Exit from both Bridger Unit 3 and Valmy Unit 2 by year-end 2025
- B2H online by summer 2026

The 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 Chapter 11. A chronological listing of the near-term actions follows in Table 1.3.

Table 1.3 Action Plan (2021–2027)

Year	Action
2022	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state commissions.
2022	Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs.
2022–2023	Jackpot Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.
2022–2024	Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger units 1 and 2. The conversion is targeted before the summer peak of 2024.
2022–2025	Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.
2022–2025	Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.
2022–2025	Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.
2022–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2022–2027	Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.
2022–2027	Work with large-load customers to support their energy needs with solar resources.
2022–2027	Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.
2025	Exit Valmy Unit 2 by December 31, 2025.
2025–2026	Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

Given the complexities and ongoing developments related to Bridger units and B2H, an update on each is provided below.

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 2021 IRP, PacifiCorp concluded it would be cost-effective to convert Bridger units 1 and 2 to natural gas beginning in 2024 while continuing to operate units 3 and 4 as coal units 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. Any new contractual terms may impact costs and assumptions, and therefore the specific timing of exits identified in the 2021 IRP.

For the 2021 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:

- Unit 1—Allowed to exit year-end 2023 or convert to natural gas. If converted to natural gas, the unit will operate through 2034.

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

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

Boardman to Hemingway

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

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

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

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

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IRP REPORT:
BACKGROUND

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 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 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, including storage, are explored in Chapter 5.

Other resources relied on for planning include 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 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 for 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 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 IPUC and 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 2021 IRPAC members can be found in *Appendix C—Technical Report*.

For the 2021 IRP, Idaho Power facilitated nine IRPAC meetings and three additional workshops. All 2021 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.

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's growing need for energy is sufficiently met, the capability of the existing system is included and then resources are added (or removed). Multiple portfolios consisting of varying resource additions are produced. Resource additions include supply-side resources like solar plus storage generation facilities; demand-side resources like energy efficiency measures; and transmission projects that increase access to energy markets. 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 forecasted and included to compare the cost effectiveness of each portfolio.

Risk

Typical of long-term planning, uncertainty grows the further into the future one attempts to evaluate. Acknowledging this uncertainty and the risk this creates, the 2021 IRP includes a robust risk analysis and approaches the subject in three different ways.

The first risk analysis method evaluates different future scenarios to test the decisions being made, especially in the near term. Future scenarios typically include multiple assumptions that fit together to define the scenario. To enhance the risk evaluation within the 2021 IRP, the company worked with the IRPAC to develop four unique future scenarios. The company ultimately used these scenarios to test whether the decisions being made within the Action Plan window (2021–2027) are robust across multiple futures. The four future scenarios are as follows:

1. Rapid Electrification
2. Climate Change
3. 100% Clean by 2035
4. 100% Clean by 2045

In addition to the scenarios above, the 2021 IRP also evaluated key inputs (e.g., natural gas and carbon price forecasts) and derived bookend assumptions (e.g., wind contract renewal assumptions) to test portfolio risk, and these are discussed in detail in Chapter 9.

The second method employed by the 2021 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.

Finally, the third method of risk analysis is qualitative which 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 2021 IRP, the company utilized the

AURORA LTCE platform to generate resource portfolios. The software evaluates how to cost-effectively meet future needs by selecting resources that are optimized within modeling constraints.

LTCE tools have evolved over time, making them more effective with each iteration of the IRP process. As an example, for the 2019 IRP, the capacity expansion software was able to optimize for the entire western interconnection; however, it was incapable of simultaneously optimizing for Idaho Power's service area and the western interconnection. Between the 2019 and 2021 IRPs, the company worked with the software provider to add functionality allowing for co-optimization between the Idaho Power and the western interconnection. As a result, the resource portfolios developed in the 2021 IRP were optimized entirely within the Aurora LTCE platform, without manual adjustments, specific to Idaho Power's balancing area.

Validation and Verification

In the 2021 IRP, to ensure the AURORA LTCE model produced an optimized portfolio, the company employed additional verification tests to ensure the model produced an optimized solution within its modeling tolerance. Verification tests were performed to validate the most economic portfolio under numerous variations of resources and timing.

To verify the AURORA-produced portfolios meet Idaho Power's reliability requirements, Idaho Power measured each portfolio's reliability by calculating a portfolio LOLE. For those portfolios that did not achieve the minimum reliability threshold, an additional reliability cost was added to the portfolio cost. This additional cost was derived from the fixed cost of a gas resource and places portfolios on a comparable reliability basis. With the additional resource adjustment, all portfolios meet the reliability threshold.

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

Energy Risk Management Policy

While the 2021 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.

IRP REPORT:

POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

2. POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor's Office of Energy and Mineral Resources, the Idaho Strategic Energy Alliance (ISEA) was established to help 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.

The ISEA strategy to accomplish this purpose rests 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 2021, the ISEA prepared the *2021 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.[1]

The *2021 Idaho Energy Landscape Report* concludes, "The strength of Idaho's economy and the quality of life in Idaho depend upon access to affordable and reliable energy resources."[1] 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 2021 report finds a weakening correlation between economic growth and energy consumption due to technological changes and the increased use of energy efficiency. Idaho's gross domestic product grew 4.8% annually from 1998 to 2018, yet Idaho's energy consumption (transportation, heat, light, and power) grew just 0.5% annually from 1998 to 2018.[1]

Despite the modest growth in energy consumption, Idaho continues to be a net importer of energy, which requires a robust and well-maintained infrastructure of highways, railroads, pipelines, and transmission lines. Approximately 23% of Idaho's electricity was composed of market purchases and energy imports from out-of-state generating resources owned by Idaho utilities.[1]

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 tributaries of the Columbia River provide energy and flexibility required to meet the demands of this growing region. Based on 2018 data, hydroelectricity is the largest source of Idaho's electricity, comprising 63%. Natural gas makes up 15%, and non-hydro renewables, principally wind power, solar, geothermal, and biomass, account for approximately 21%.[1] Idaho's electricity rates were the third lowest among the 50 states and the District of Columbia in 2019.[1]

[1] https://oemr.idaho.gov/wp-content/uploads/Idaho-Energy-Landscape-2021.pdf. Accessed September 2021.

State of Oregon 2020 Biennial Energy Report

In 2017, the Oregon Department of Energy (ODOE) introduced House Bill (HB) 2343, which charges the ODOE to develop a new biennial report to inform local, state, regional, and federal energy policy development and energy planning and investments. The *2020 Biennial Energy Report*[2] 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.

The biennial report shows an evolving energy supply in Oregon. While Oregon's energy consumption consists primarily of hydroelectric power, coal, and natural gas, renewable energy continues to make up an increasing share of the 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 has dropped since 2005. Natural gas, a resource that can help to integrate the hourly variation of renewable resources and help smooth out seasonal hydro variation, has steadily increased its share of Oregon's resource mix since 1990.

The main theme of the 2020 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, policy makers, state and local governments, and private-sector business and industry leaders.[3]

FERC Relicensing

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years, depending on the size, complexity, and cost of the project.

Hells Canyon Dam

Idaho Power's remaining and most significant ongoing relicensing effort is for the Hells Canyon Complex (HCC). The HCC provides approximately 70% of

[2] https://energyinfo.oregon.gov/ber. Accessed September 2021.

[3] Oregon Department of Energy, *2020 Biennial Energy Report*.

Idaho Power's hydroelectric generating capacity and 30% of the company's total generating capacity. The original license for the HCC expired in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under annual licenses issued by FERC. 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, further enabling the achievement of Idaho Power's 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* (ESA); 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 ESA, among other actions.

Efforts to obtain a new multi-year license for the HCC are expected to continue until a new license is issued, which Idaho Power believes is likely in 2024 or thereafter.

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 (PM&E) 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. Its FERC license expires in 2025.

Relicensing activities include the following:

- Coordinating the relicensing process
- Consulting with regulatory agencies, tribes, and interested parties on resource and legal matters

- Preparing and conducting studies on fish, wildlife, recreation, archaeological resources, historical flow patterns, reservoir operations and load shaping, forebay and river sedimentation, and reservoir contours and volumes
- 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 PM&E 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.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2021 IRP.

Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for 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. Idaho Power's ongoing participation in water-right issues and studies is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.

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 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 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 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 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 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. Idaho Power and the State of Idaho are actively involved in those discussions. The settlement recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as managed aquifer-recharge projects—to benefit agricultural development and hydroelectric generation.

Idaho Power initiated and pursued a successful weather modification (cloud seeding) program in the Snake River Basin. The company then partnered with an existing program in the Upper Snake River Basin and has cooperatively expanded the existing weather-modification program, along with forecasting and meteorological data support. In 2014, Idaho Power expanded its cloud-seeding program to the Boise and Wood River basins, in collaboration with basin water users and the Idaho Water Resource Board (IWRB). Wood River cloud seeding, along with the Upper Snake River activities, will benefit the Eastern Snake River Plain Aquifer (ESPA) Comprehensive Aquifer Management Plan implementation through additional water supply.

Water-management activities for the ESPA are currently being driven by the recent agreement between the Surface Water Coalition and the Idaho Ground Water Appropriators. This agreement 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 provides 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 provides 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. The plan 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.

On November 4, 2016, Idaho Department of Water Resources (IDWR) Director Gary Spackman signed an order creating a Ground Water Management Area (GWMA) for the ESPA. Spackman 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.

Spackman 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.

Variable Energy Resource Integration

Since the mid-2000s, Idaho Power has completed multiple studies investigating the impacts and costs associated with integrating VERs, such as wind and solar, without compromising reliability. Idaho Power's most recent VER Integration study was completed in 2020.

For the 2020 VER Integration study, Idaho Power worked in conjunction with a technical review committee and retained Energy and Environmental Economics, Inc. (E3) to perform the study. Through the analysis, E3 determined updated VER integration costs and regulation reserve requirements for various VER addition scenarios for a 2023 model year.

Improving on the 2018 VER study to model Idaho Power's new participation in the EIM, E3's analysis utilized Energy Exemplar's PLEXOS software to allow for modeling the system in four stages: day ahead, hour ahead, 15-minute, and 5-minute markets. Idaho Power joined the EIM in the second quarter of 2018. The addition of the EIM market allows for balancing of forecast errors in real time.

In compliance with Order 21-198 in Oregon Docket UM 1730, Idaho Power filed the 2020 VER study, which described the methods followed by Idaho Power to estimate the amounts of regulating reserves necessary to integrate VER without compromising system reliability.

The methods followed in the 2020 VER study yielded estimated regulating reserve requirements necessary to balance the netted system of load, wind, and solar (net load).

For the 2021 IRP analysis, the 2020 VER study defined the 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, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2021 IRP include defining hourly reserve requirements for "Load Up," "Load Down," "Solar Up," "Solar Down," "Wind Up," and "Wind Down."

Oregon Community Solar Program

In 2016, the Oregon Legislature enacted Senate Bill (SB) 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 photovoltaic 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 the date of this IRP filing, 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 a planned in-service date of July 2022. The company believes the project is well positioned to obtain the necessary certifications to participate in the program. 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 operational until mid-2022, 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.

Renewable Energy Certificates

A REC, also known as a green tag, represents the green or renewable attributes of energy produced by a certified renewable resource. Specifically, a REC represents the renewable attributes associated with the production of 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The purchase of a REC buys the renewable attributes, or "greenness," of that energy.

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1 MWh of electricity produced. RECs produced by a certified renewable resource can either be sold together with the energy (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level renewable portfolio standard (RPS). An RPS is a policy requiring a minimum amount (usually a percentage) of the electricity each utility delivers to customers to come from renewable energy resources. See Idaho Power's RPS Obligations in the Renewable Portfolio Standard section. The entity that retires a REC can also claim the renewable energy attributes of the corresponding amount of energy delivered to customers.

A certification system gives each REC a unique identification number to facilitate tracking purchases, sales, and retirements. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used (retired), held (banked), or traded (sold).

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- REC supply/demand
- Whether the REC is certified for RPS compliance
- The generation type associated with the REC (e.g., wind, solar, geothermal)
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds are returned to Idaho Power customers through each state's power cost adjustment (PCA) mechanisms as directed by the IPUC in Order No. 32002 and by the OPUC in Order No. 11-086. Idaho Power cannot claim the renewable attributes associated with RECs that are sold. The new REC owner has purchased the rights to claim the renewable attributes of that energy.

Clean Energy Your Way

On Thursday, December 2, 2021, the company filed an application with the IPUC to expand optional customer clean energy offerings through the Clean Energy Your Way 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. This request 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.

More specifically, the company requested authority to 1) rename the existing Idaho Schedule 62 Green Power Purchase Program Rider to Clean Energy Your Way—Flexible, 2) establish a regulatory framework for a future voluntary subscription green power service offering named Clean Energy Your Way—Subscription, and 3) offer a tailored renewable option to the company's largest customers (Special Contract and Schedule 19, Large Power Service) named Clean Energy Your Way—Construction.

While the Flexible option (Schedule 62—Green Power Program) is currently available to customers in both Idaho and Oregon; the Subscription and Construction options will initially be offered to the company's Idaho customers.

This proposed program provides three options for customers to purchase renewable energy:

Clean Energy Your Way—Flexible

The Flexible offering is a renaming of the existing Green Power Program. Business and residential customers would continue to purchase renewable energy in blocks of 100 kilowatt-hours (kWh) or covering 100% of their usage.

This option is available today in both Idaho and Oregon as Schedule 62—Green Power Program. Once the Clean Energy Your Way proposal is approved, the option will remain, but under the new name.

Clean Energy Your Way—Subscription

The Subscription offering will provide opportunities for business and residential customers in Idaho to receive an amount of renewable energy equal to either 50% or 100% of their historic average annual energy use by subscribing to a new renewable resource. This resource would be built upon approval of the IPUC—the type and timing of the resource would be determined through a subsequent phase of the implementation process, with size dependent upon customer interest. Subscription terms are 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.

This offering will require a two-phase approval process by the IPUC. Upon IPUC approval to offer a voluntary subscription option, the next step will be to identify a new renewable resource to serve the program, then return to the IPUC for approval to develop that resource and establish customer pricing for the program. In the interim, Idaho Power has provided an opportunity for customers to express interest in the Subscription offering so the company can provide updates as the program progresses.

Clean Energy Your Way—Construction

The Construction offering will enable industrial customers (Special Contract and Schedule 19 customers) to partner with Idaho Power to develop new renewable resources through a long-term arrangement. Customers would have the ability to 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 would claim the renewable attributes as their own.

This offering will require detailed, negotiated contracts between an Idaho customer and Idaho Power that will require individual approval by the IPUC.

Renewable Portfolio Standard

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 2020 per United States Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.4% 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 House Bill 2021, which sets greenhouse gas emissions reduction requirements associated with electricity sold to utility customers. Idaho 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.

Carbon Adder/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 greenhouse gas (GHG) 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.

In January 2021, the new presidential 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 rejoined the United States to the Paris Agreement on climate change, which requires commitments to reduce 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 are requirement to achieve net-zero emissions from federal procurement and from overall federal operations by 2050.[4]

On March 2, 2021, the House Energy and Commerce Committee released a discussion draft of the Climate Leadership and Environmental Action for Our Nation's Future Act (CLEAN Future Act), which is intended to achieve the committee's goal of reaching economy-wide net-zero GHG emissions by 2050. Title II of the CLEAN Future Act includes a suite of measures focused on the United States electric power sector. As proposed, Subtitle A includes a nationwide clean electricity standard, which would require all retail electricity suppliers to obtain 100% of their electricity from clean energy sources by 2035. With the CLEAN Future Act still in draft form, it is unclear what will be required, if anything, as a clean energy standard for electricity suppliers.

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

IRP REPORT:

CLIMATE CHANGE

3. CLIMATE CHANGE

Idaho Power recognizes the need to assess the impacts of climate change on our industry, customers, and on long-term planning. The company undertakes a variety of analysis exercises and impact evaluations to understand and prepare for climate change. This new 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

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 year-end 2028.

The Preferred Portfolio identified in this 2021 IRP reflects a clean mix of generation and transmission resources that ensures reliable, affordable energy using technologies available today. Achieving our 100% clean energy goal, however, will require technological advances and reductions in cost, as well as a continued focus on energy efficiency and demand-response programs. As it has over the past 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.

Idaho Power Carbon Emissions

Limiting the impact of climate change requires reducing GHG emissions, primarily CO_2. Idaho Power's CO_2 emission levels have historically been well 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 graph 3.1 and 3.2 with the dashed black line indicating the long-term trend and the green line indicating the actual annual amounts.

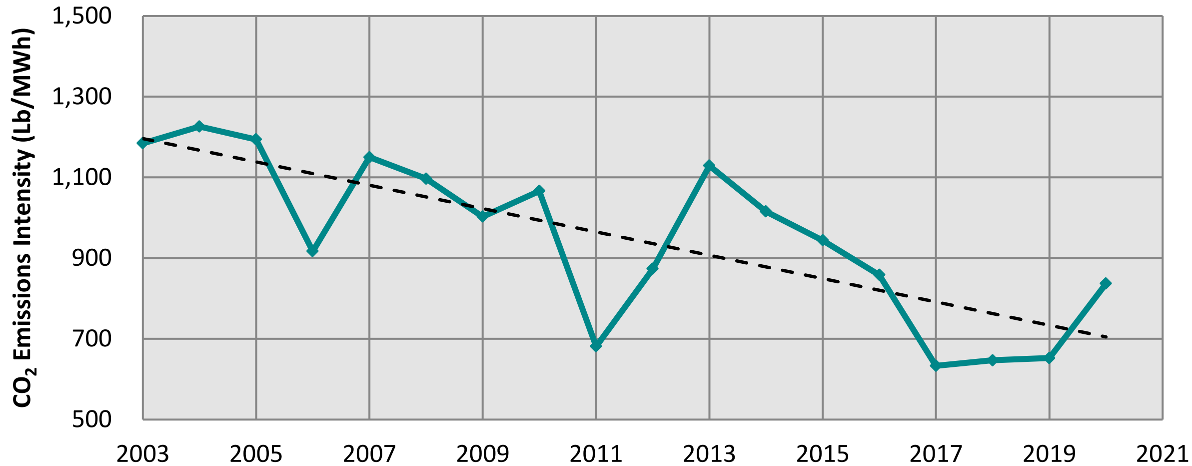

Figure 3.1 Estimated Idaho Power CO_2 emissions intensity

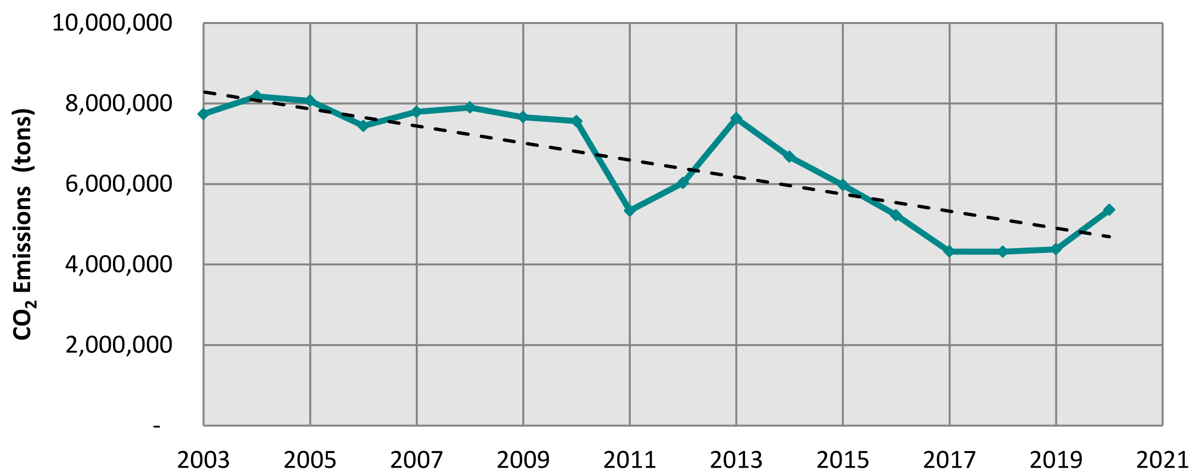

Figure 3.2 Estimated Idaho Power CO_2 emissions

Idaho Power is committed to reducing the amount of CO_2 emitted from energy-generating sources. Since 2009, the company has met various voluntary goals to realize its commitment to CO_2 reduction. From 2010 to 2020, 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 2021 IRP assumes carbon emissions are subject to a per-ton cost of carbon. The carbon cost forecasts are provided in Chapter 9, while the projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 10.

Energy Mix

Combined with the energy purchased from power purchase agreements (PPA) and *Public Utility Regulatory Policies Act of 1978* (PURPA) projects, Idaho Power's resource mix was approximately 60% clean in 2020 (see below).[5] The company's generation mix is primarily driven by hydropower, which is considered a clean energy source for producing virtually no carbon emissions.

Notably, included in the company's 2020 energy mix was over 1,200 megawatts (MW) of power purchase contracts for renewable energy (primarily PURPA projects). The various contracts included 728 MW of wind, 316 MW of solar, 147 MW of small hydropower and 35 MW of geothermal.

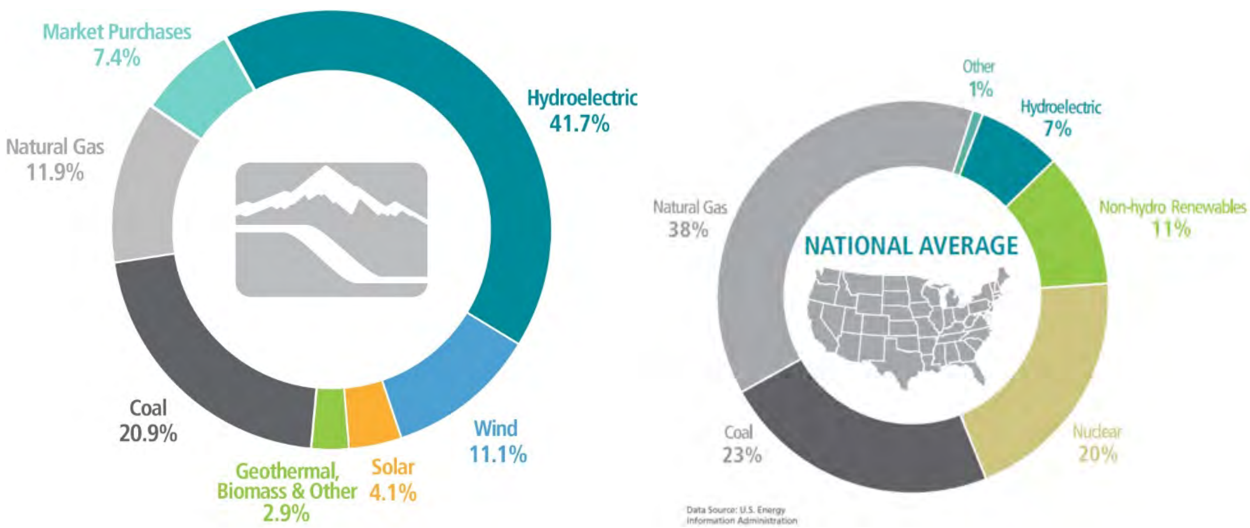

Figure 3.3 Idaho Power's 2020 energy mix compared to the national average

The company's path away from coal resources is evident in the 2021 Preferred Portfolio and notably in the near-term Action Plan. The addition of renewable resources over the 20-year study period combined with the completion of the Boardman to Hemingway (B2H) transmission

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

line in 2026, will drastically change the company's energy mix in the future to include primarily clean resources.

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."[6]

More regionally focused studies have assessed the potential impact of climate change on the Pacific Northwest. The Fourth National Climate Assessment[7] and the River Management Joint Operating Committee (RMJOC) [8] 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 2021 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 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

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[6] P. 8, https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM_final.pdf

[7] https://nca2018.globalchange.gov/

[8] https://www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

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 as a result of climate change can adversely affect Idaho Power's operating results and cause them to fluctuate seasonally. Climate change could also have significant physical effects in Idaho Power's service area, such as increased frequency and severity of storms, lightning, droughts, heat waves, fires, floods, snow loading, and other extreme weather events. These events and their associated impacts could damage transmission, distribution, and generation facilities, causing service interruptions and extended outages, increasing costs and other operating and maintenance expenses—including emergency response planning and preparedness expenses—and limiting 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 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 forecasting capabilities. The company expects this system to help improve the integration of renewable energy sources into the electrical grid and help Idaho Power manage hydroelectric system and cloud-seeding operations. Such advances improve Idaho Power's ability to provide affordable, clean energy to meet the region's growing needs.

Wildfire Risk

In recent years, the Western United States has experienced an increase in the frequency and intensity of wildland fires (wildfires). A variety of 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 Idaho and Oregon service area.

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

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. 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 will be reviewed annually in advance of each fire season.[9]

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—along with the associated harms associated with 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 operates a robust 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.

[9] https://docs.idahopower.com/pdfs/Safety/2021WildfireMitigationPlan.pdf

Water and Hydropower Generation Risk

Factors contributing to lower hydropower generation can increase costs and negatively impact Idaho Power's financial condition and results of operations, 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 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.

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. In addition, Idaho Power provides forecasting and meteorological data support.

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 (RMJOC-II) 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 adverse effect 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 House Bill 2021 sets emission 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 2021 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 all addressed and accounted for in different operational ways by Idaho Power, the company also extended climate-related risk assessment to the 2021 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.

The company conducted a Rapid Electrification scenario at the request of IRPAC members. This scenario was 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 10. This aggressive forecast assumes over half a million electric vehicles as well as adoption of an 80% penetration of heat pump technology at residences within the company's service area by 2040.

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

To model risk associated with carbon regulation, Idaho Power has assessed the risk in two ways. First, the company created "100% Clean by 2035" and "100% Clean by 2045" scenarios that remove carbon price adder forecasts and assume a legislative mandate to move toward 100% clean energy by the years 2035 and 2045, respectively. Second, the company estimated the portfolio cost of six core portfolios under three different carbon price forecasts (see Chapter 9 for more information on the six portfolios: Base with B2H, Base with B2H without Gateway West, Base with B2H PAC Bridger Alignment, Base without B2H, Base without B2H without Gateway West, and Base without B2H PAC Bridger Alignment).

By considering the above scenarios and varying assumptions, the 2021 IRP has a robust method for assessing possible risk associated with both mitigation and adaptation to climate change.

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Customer Load and Growth

In 1996, Idaho Power served approximately 351,000 customers. In 2021, Idaho Power served more than 600,000 customers in Idaho and Oregon. Firm peak-hour load has increased from 2,437 MW in 1996 to 3,751 MW in 2021—a new system peak hour record reached on June 30, 2021.


Residential construction growth in southern Idaho.

Average firm load increased from 1,438 average MW (aMW) in 1996 to 1,809 aMW in 2020 (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 over 5.0 kW to the peak-hour load and over 3 average kW (akW) to the average load.

Since 1996, Idaho Power's total nameplate generation has increased from 2,703 MW to 3,389 MW. Table 4.1 shows Idaho Power's changes in reported nameplate capacity since 1996.

Idaho Power anticipates adding approximately 13,300 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 nearly 55 MW per year, and the average-energy requirement is forecast to grow about 30 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

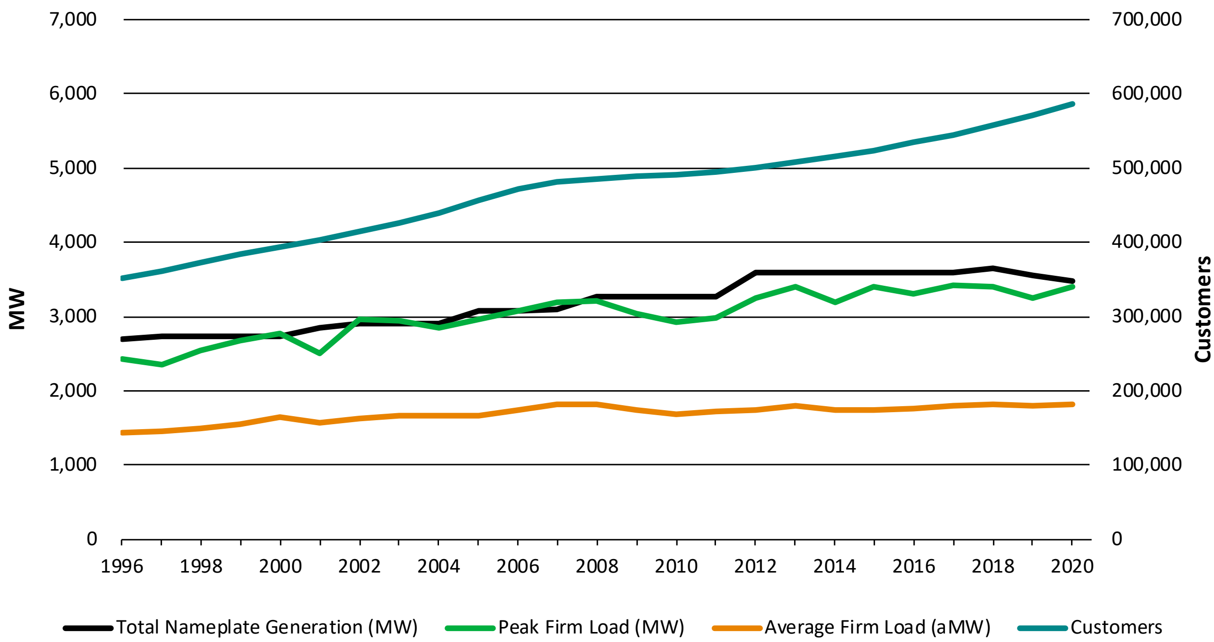

Figure 4.1 Historical capacity, load, and customer data

Table 4.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1996	2,703	2,437	1,438	351,261
1997	2,728	2,352	1,457	361,838
1998	2,738	2,535	1,491	372,464
1999	2,738	2,675	1,552	383,354
2000	2,738	2,765	1,654	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,623	414,062
2003	2,912	2,944	1,658	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,661	456,104
2006	3,085	3,084	1,747	470,950
2007	3,093	3,193	1,810	480,523
2008	3,276	3,214	1,816	486,048
2009	3,276	3,031	1,744	488,813
2010	3,276	2,930	1,680	491,368
2011	3,276	2,973	1,712	495,122
2012	3,594	3,245	1,746	500,731
2013	3,594	3,407	1,801	508,051
2014	3,594	3,184	1,739	515,262
2015	3,594	3,402	1,748	524,325
2016	3,594	3,299	1,750	533,935

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
2017	3,594	3,422	1,807	544,378
2018	3,659	3,392	1,810	556,926
2019	3,547	3,242	1,790	570,953
2020	3,389[2]	3,392	1,809	586,565
YTD 2021	n/a	3,751	1,885	601,616

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

2 Reported nameplate capacity aggregation methodology changed for 2020.

3 2021 year to date values are as of Nov 30, 2021.

2020 Energy Sources

Idaho Power's energy sources for 2020 are shown in Figure 3.3. Idaho Power-owned generating capacity was the source for about 75% of the energy delivered to customers. Hydroelectric production from company-owned projects was the largest single source of energy at about 42% of the total. Coal contributed about 21%, and natural gas and diesel generation contributed about 12%. Purchased power accounted for the remainder of the total energy delivered to customers. Much of the purchased power was from long-term energy contracts (PURPA and PPA projects), primarily from wind, solar, hydro, geothermal, and biomass projects (in order of decreasing percentage). While Idaho Power receives production from PURPA and PPA projects, the company sells the RECs it receives associated with the production and does not represent the energy from these projects as renewable energy delivered to customers.

Existing Supply-Side Resources

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

Table 4.2 Existing resources

Resource	Type	Nameplate 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

Resource	Type	Nameplate Capacity (MW)	Location
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	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Jim Bridger[10]	Coal	707.0	Southwest Wyoming
North Valmy[11]	Coal	134.0	North Central Nevada
Langley Gulch	Natural Gas—CCCT	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT	164.2	Southwest Idaho
Danskin	Natural Gas—SCCT	261.4	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,388.9**	

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 1,773 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.

[10] Idaho Power owns one-third of the plant. Idaho Power's share of the plant's capacity is 707 MW.

[11] Idaho Power owns 50% of the plant. Idaho Power's share of the remaining Unit 2 is 134 MW.

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 equals 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 Article 42 of 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 full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The United States Bureau of Reclamation (USBR) releases water from USBR 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 elevation 2,059 (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 has continued to provide these flow augmentation releases annually through 2021.

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, or redds. During fall Chinook operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour 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, Lower Salmon, Upper 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[12] also helps the company improve water-quality and temperature conditions in the Snake River 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.

[12] https://idwr.idaho.gov/iwrb/programs/water-supply-bank/

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in 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.

Cloud seeding ground generator

Idaho Power seeds clouds by introducing silver iodide (AgI) 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 AgI at high elevations
2. Modified aircraft burning flares containing AgI

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

AgI 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 without any known harmful effects.[13] 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 11.3%. Idaho Power estimates cloud seeding, on average, provides an additional 415,000 acre-feet in the Upper Snake River, 105,000 acre-feet in the Wood River Basin, 264,000 acre-feet in the Boise Basin, and 221,000 acre-feet from the Payette River Basin, for a total average annual benefit of 1,006,000 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

[13] weathermod.org/wp-content/uploads/2018/03/EnvironmentalImpact.pdf

approximately 1,280,000 acre-feet. The additional water from cloud seeding helps fuel the hydropower system along the Snake River.

Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment (SNOWIE) was a joint project between the National Science Foundation and Idaho Power. 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. Groundbreaking discoveries continue to be evaluated from this dataset collected in winter 2017. Multiple scientific papers have already been published,[14] 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 includes 32 remote-controlled, ground-based generators and two aircraft for Idaho Power-operated cloud seeding in the central mountains of Idaho (Payette, Boise, and Wood River basins). The Upper Snake River Basin program includes 25 remote-controlled, ground-based generators and one aircraft operated by Idaho Power targeting the Upper Snake, as well as 25 manual, ground-based generators operated by a coalition of stakeholders in the Upper Snake.

During the 2021 legislative session, House Bill 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 have 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 Idaho Water Resources Board.

[14] 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, 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's 2021 IRP preferred portfolio includes a coal-to-gas conversion of units 1 and 2.[15] For additional details on the Jim Bridger plant, refer to Chapter 8, Planning Period Forecast. For the 2021 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.

North Valmy

Idaho Power's participation in the operations of North Valmy Unit 1 ceased at year-end 2019. Idaho Power currently participates 50%, or 134 MW, in the second generating unit at the North Valmy coal power plant located near Winnemucca, Nevada. NV Energy is the other 50% participant and is the operator of the North Valmy facility. For the AURORA-based capacity expansion modeling performed for the 2021 IRP analysis, Idaho Power required an exit from Unit 2 participation no later than year-end 2025 and no earlier than year-end 2023.

Natural Gas Facilities and Diesel Units

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 164 MW Siemens–Westinghouse 501F natural gas simple-cycle combustion turbine (SCCT) located east of the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant is dispatched as needed to support system load.

Danskin

The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 171 MW Siemens 501F and two 45 MW Siemens–Westinghouse W251B12A SCCTs at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, which uses a nominal 318-MW natural gas combined-cycle combustion turbine (CCCT). The plant consists of one 187 MW Siemens

[15] Docketed as LC 77 in Oregon and PAC-E-21-19 in Idaho, PacifiCorp's 2021 IRP discusses coal-to-gas conversion of Jim Bridger units 1 and 2 at pp. 298-299, 322.

STG-5000F4 combustion turbine and one 131.5 MW Siemens SST-700/SST-900 reheat steam turbine. The Langley Gulch plant, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012. In early 2022, the Langley Gulch plant will go through an overhaul to upgrade the gas combustion turbine. The upgrade will allow for the maximum-rated exhaust gas temperature of the units to increase and it will increase both the thermal efficiency and the total capacity of the plant. Once the upgrade is completed, it is expected that the total nameplate of the plant will increase to 365 MW.

Diesel

Idaho Power owns and operates two diesel generation units in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are operated during emergency conditions, primarily for voltage and load support.

Solar Facilities

Solar End-of-Feeder Project

The Solar End-of-Feeder Pilot Project is a small-scale (18 kW) proof-of-concept PV system evaluated as a non-wires alternative to traditional methods to mitigate low-voltage near the end of a distribution feeder. The purpose of the pilot was to evaluate its operational performance and its cost-effectiveness compared to traditional low-voltage mitigation methods. Traditional methods for mitigating low voltage include the addition of capacitor banks, voltage regulators, or reconductoring.

Solar installation as part of the Solar End-of-Feeder Pilot Project.

Capacitor banks and voltage regulators are relatively inexpensive solutions compared to reconductoring, but these solutions were not viable options for this location due to distribution feeder topology.

The Solar End-of-Feeder Pilot Project was installed and has been in operation since October 2016. The project has operated as expected by effectively mitigating low voltage.

Customer Generation Service

Idaho Power's on-site generation and net metering 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 March 31, 2021, there were 7,354 solar PV systems interconnected through the company's customer generation tariffs with a total capacity of 65.163 MW. At that time, the company had received completed applications for an additional 720 solar PV systems, representing an incremental capacity of 23.431 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 March 31, 2021

Resource Type	Active	Pending	Total
Idaho Total	7,327	712	8,039
Solar PV	7,284	711	7,995
Wind	32	1	33
Other/hydroelectric	11	0	11
Oregon Total	**70**	**9**	**79**
Solar PV	70	9	79
Wind	0	0	0
Other/hydroelectric	0	0	0
Idaho Power Total	**7,397**	**721**	**8,118**

Table 4.4 Customer generation service generation capacity (MW) as of March 31, 2021

Resource Type	Active	Pending	Total
Idaho Total	64.098	23.109	87.208
Solar PV	63.761	23.101	86.863
Wind	0.179	0.008	0.187
Other/hydroelectric	0.158	0.000	0.158
Oregon Total	1.402	0.329	1.731
Solar PV	1.402	0.329	1.731
Wind	0.000	0.000	0.000
Other/hydroelectric	0.000	0.000	0.000
Idaho Power Total	**65.500**	**23.439**	**88.939**

Oregon Solar Photovoltaic Pilot Program

In 2009, the Oregon Legislature passed Oregon Revised Statute 757.365 as amended by HB 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar PV Pilot Program in 2010, offering volumetric incentive rates to customers in Oregon. Under the pilot program, Idaho Power acquired 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW were allocated, and the remaining 200 kW were offered during an enrollment period in October 2011. However, because some PV systems were not completed from the 2011 enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In 2013, the Oregon Legislature passed HB 2893, which increased Idaho Power's required capacity amount by 55 kW. An enrollment period was held in April 2014, and all capacity was allocated, bringing Idaho Power's total capacity in the program to 455 kW.

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. CSPP are often associated with PURPA. Individual states were tasked with establishing 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.

As of July 1, 2021, Idaho Power had 131 PURPA contracts with independent developers for approximately 1,140.40 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 131 contracts, 129 were online as of July 1, 2021, with a cumulative nameplate rating of approximately 1,136.6 MW. Figure 4.2 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

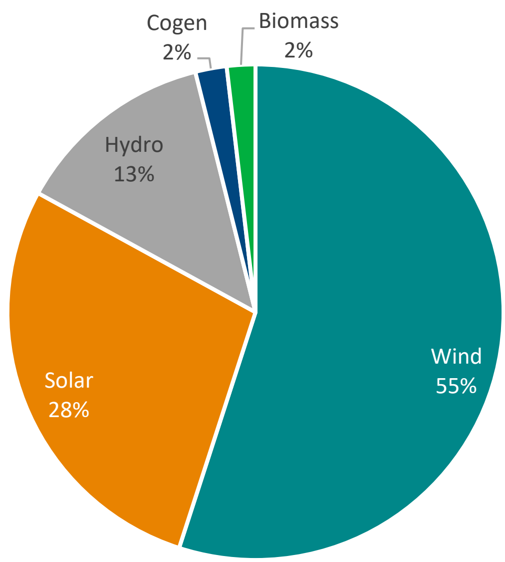

Figure 4.2 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. To account for likely variability in future PURPA resources, the 2021 IRP includes three contract renewal scenarios for existing PURPA resources: a 25% base case renewal rate and 0% and 100% low and high case bookends. Generation from PURPA contracts is forecasted early in the IRP planning process to update the accounting of supply-side resources available to meet load. The PURPA forecast used in the 2021 IRP was completed in December 2020. 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 was constructed during 2007 and 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 Unit 1

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

On March 22, 2019, Idaho Power and Jackpot Holdings, LLC, entered a 20-year PPA for the purchase and sale of 120 MW of solar electric generation from the Jackpot Solar facility to be built 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 is scheduled to be online in December 2022.

An application was submitted to the IPUC on April 4, 2019, requesting an order approving the PPA, and on December 24, 2019, the IPUC issued Order No. 34515 approving the Jackpot Solar PPA. On the same day as the IPUC application, Idaho Power submitted a notice to the OPUC, in accordance with OAR 860-089-0100(3) and (4), of an exception from Oregon's competitive-bidding requirements for electric utilities, as the PPA with Jackpot Holdings presents a time-limited opportunity to acquire a resource of unique value to Idaho Power customers.

Late in the 2021 IRP development process, the project developer informed Idaho Power they may not be able to meet the in-service date specified in the contract. For IRP purposes, all cases assumed Jackpot Solar was in-service per the terms of the contract; however, if Jackpot Solar is not online in 2023, the company will have an additional 40.8 MW load and resource balance deficit in 2023. Given the near-term nature of this possible deficit, the company's operations teams are evaluating options.

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 18-MW 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. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, with the initial exchange agreement with Idaho Power ending in 2015. At the end of the initial term, Idaho Power exercised its right to extend the agreement through 2020. At the end of the 2020 term, Idaho Power once again exercised its right to extend the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 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 is especially dependent on the regional power market purchases during peak-load periods. The existing transmission system is used to import the power purchases. A reliance on regional power markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

Transmission MW 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. Idaho Power reserves portions of its transmission capacity to import energy for load service (network set-aside); this 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).

Idaho Power continually evaluates market opportunities to meet near-term needs. Idaho Power currently has one wholesale energy market purchase for peak hours in July and August for 2021 through 2024 for 75 MW. Idaho Power does not currently have any long-term wholesale energy sales contracts.

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IRP REPORT:

FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

5. FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

Generation Resources

Supply-side generation resources include traditional generation resources, renewable resources, 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 2021 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 2021 IRP is the 2020 Annual Technology Baseline report released by the National Renewable Energy Laboratory (NREL) in July 2020.[16] 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 all the resources considered and cost information, refer to Chapter 8. All cost information presented is in nominal dollars with an online date of 2023 for all levelized cost of energy (LCOE) calculations. The levelized cost figures are based on Idaho Power's cost of capital.

Resource Contribution to Peak

For the 2019 IRP, Idaho Power calculated the contribution to peak of solar using the 8,760-based method developed by NREL; for the 2021 IRP, Idaho Power has since updated and expanded the contribution to peak calculations to analyze solar, wind, demand response, storage, and solar plus storage using the Effective Load Carrying Capability (ELCC) methodology. ELCC is a reliability-based metric used to assess the contribution to peak of any given power plant.

The ELCC of a resource is determined by first calculating the perfect generation required to achieve an LOLE of 0.05 days per year. Then, the resource being evaluated is added to the system, and the perfect generation required is calculated again. The ELCC of a given resource is equal to the difference in the size of the perfect generators (from the two evaluations previously mentioned) divided by the resource's nameplate.

To account for weather variations in the data, four different test years were used; the results from each of the test years were then averaged to produce a singular contribution to peak for each specified variable resource to be used in the AURORA model. ELCC values for future solar,

[16] atb.nrel.gov/

wind, demand response, storage, and solar plus storage can be found in the corresponding resource sections of chapters 5 and 6.

Idaho Power developed a tool to calculate LOLE and ELCC[17]. For more information regarding the methodologies and calculations used for this analysis, see the Loss of Load Expectation section of *Appendix C—Technical Report* of the 2021 IRP.

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 2021 IRP, a variety of renewable resources were included in many of the portfolios analyzed. Renewable resources are discussed in general terms in the following sections.

Hydroelectric

Hydroelectric power is the foundation of Idaho Power's electrical generation fleet. The existing generation is low cost and does not emit carbon.

Large hydroelectric pumped storage projects are a potential way to add significant hydropower to the region. Pumped storage projects can often site the main upper reservoir away from the main river, which reduces its impact on the primary water body. Closed loop systems are completely disconnected from the main surface water body and only require additional water to overcome evaporative and seepage losses. Pumped storage can provide significant capacity and energy when it is needed and integrate additional VERs on the electrical system. Such a venture could also be pursued as a collaborative effort with other utilities.

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.

Solar

The primary types of solar generation technology are utility-scale PV and distributed PV. Sunlight is composed of photons, or particles of solar energy that contain various amounts of energy corresponding to the different wavelengths of the solar spectrum. Solar cells are made from semiconductor materials that convert sunlight into electricity according to the principle of photovoltaic effect. The photovoltaic effect is the generation of a voltage difference at the junction of two different materials upon exposure to light. The PV modules produce electricity when photons are absorbed into a semiconductor junction. DC energy passes through an inverter, converting it to AC that can then be used on-site or sent to the grid.

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

Solar insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter (m^2) per day (daily insolation average over a year). The higher the insolation number, the better the solar-power potential for an area. NREL insolation charts[18] show the desert southwest has the highest theoretical solar potential in the continental United States.

Modern solar PV technology has existed for many years but has historically been cost prohibitive. Improvements in technology and manufacturing, combined with increased demand, have made PV resources more cost competitive with other renewable and conventional generating technologies.

Rooftop solar was considered in two forms as part of the 2021 IRP: residential rooftop solar and commercial solar.

Advancements in energy storage technologies have focused on coupling storage devices with solar PV resources to mitigate and offset the effects of the resource's variability. This coupling or pairing of resources was modeled and considered in the 2021 IRP. For a more complete description of battery storage, refer to the Storage Resources section of this chapter.

The average ELCC value for future stand-alone solar projects was 10.2%.

The average ELCC value applied to future solar plus storage projects was 97% with 4-hour storage durations.

For Idaho Power's cost estimates, operating parameters, and ELCC calculations for single-axis tracking, utility-scale PV resources, see the Supply-Side Resource and Loss of Load Expectation sections of *Appendix C—Technical Report* of the 2021 IRP.

Targeted Grid Solar and Storage

Idaho Power analyzed transmission and distribution (T&D) deferral benefits associated with targeted solar, storage, and solar with storage. The analysis included the following:

1. **Deferrable Investments**: Potentially deferrable infrastructure investments were identified spanning a 20-year period from 2002 through 2021. The infrastructure investments served as a test bed to identify the attributes of investments required to serve Idaho Power's growing customer base and whether those investments could have been (or could be) deferred with solar and/or storage. Transmission, substation, and distribution projects driven by capacity growth were analyzed. The limiting capacity was identified for each asset, along with the recommended in-service date, projected cost, peak loading, peak time of day, and projected growth rate.

18 https://www.nrel.gov/gis/solar-resource-maps.html

2. **Solar Contribution**: The capacity demand reduction from varying amounts of solar was analyzed. Irradiance data was assumed to be consistent throughout the service area. The following was assumed for solar projects:
    - Rooftop solar: fixed, south facing
    - Large-scale solar: single-axis tracking
3. **Storage Contribution**: The capacity demand reduction from varying amounts of utility-scale storage was analyzed. The systems were chosen from readily available lithium-ion (Li-ion) battery storage systems. The storage systems were selected in multiples of 1 MW and 4-hour duration size.
4. **Solar with Storage Contribution**: A combination of large-scale solar with utility-scale storage.
5. **Methodology**: If the net forecast (electrical demand minus an assumed storage export contribution) was below the facility limiting capacity, the project could have been (or could be) deferred. The financial savings of deferring the project were then calculated.

Idaho Power selected five infrastructure investments from the data set that could have been deferred with varying amounts of storage. The selections were made to represent different areas, project sizes, and deferral periods, as well as the frequency at which projects are likely to be deferrable on Idaho Power's system. The storage required to achieve each deferral and the value of each deferral varied (Table 5.1).

Table 5.1 Storage capacity required to defer infrastructure investments

Location	Years Deferred	Deferral Savings	Storage Project Size (kW)	Capacity Value ($/kW)
Weiser	10	$379,546	2,000	$189.77
Elmer (Mountain Home)	14	$706,822	4,000	$176.71
Hidden Springs (Boise)	5	$377,350	2,000	$188.68
Cascade	5	$673,840	2,000	$336.92
Filer	10	$1,848,112	2,000	$924.06

The average capacity value of the identified investments was $363.23 per kW. This value was used for the T&D deferral locational value.

It is anticipated that a locational value of T&D deferral may apply to an annual average of 5,000 kW of storage over the 20-year IRP forecast for a total potential of 100 MW of storage. This resource option was added to the AURORA LTCE model.

While solar can sometimes be used to offset T&D investment, the instances are infrequent. Batteries can provide T&D deferral value and are a necessary 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 it is for solar or solar plus battery installations.

Geothermal

Potential for commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary-cycle technologies. Based on exploration to date in southern Idaho, binary-cycle geothermal development is more likely than flashed steam within Idaho Power's service area. The flashed steam technology requires higher water temperatures. Most optimal locations for potential geothermal development are believed to be in the southeastern part of the state; however, the potential for geothermal generation in southern Idaho remains somewhat uncertain. The time required to discover and prove geothermal resource sites is highly variable and can take years.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300 ^{o}Fahrenheit or greater. Binary-cycle technology is used for lower temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low-boiling-point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine/generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

For Idaho Power's cost estimates and operating parameters for binary-cycle geothermal generation, see the Supply-Side Resource section of *Appendix C—Technical Report* of the 2021 IRP.

Wind

Modern wind turbines effectively collect and transfer energy from windy areas into electricity. A typical wind development consists of an array of 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. Wind energy sites in areas that receive consistent, sustained winds greater than 15 miles per hour are the best candidates for development.

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. Wind resources present operational challenges for electric utilities and system operators due to the variable nature of wind-energy generation. To adequately account for the unique characteristics of wind energy, resource planning of new wind resources requires estimates of the expected annual energy and capacity contribution. The 2021 IRP assumed an annual average capacity factor of 35% for projects sited in Idaho and 45% for projects sited in Wyoming.

The average ELCC value applied to future wind projects was 11.2%.

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* of the 2021 IRP.

Biomass

The 2021 IRP includes anaerobic digesters as a resource alternative. 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. Of the biomass technologies available, the 2021 IRP considers anaerobic digesters as the best fit for biomass resources within the service area.

For Idaho Power's cost estimates and operating parameters for an anaerobic digester, see the Supply-Side Resource section of *Appendix C—Technical Report* of the 2021 IRP.

Thermal Resources

While renewable resources have garnered significant attention in recent years, 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 resources, nuclear, and coal.

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 a major natural gas pipeline.

Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial, dispatchable power generation in the region. 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% (lower heating value) under ideal conditions.

A traditional CCCT plant consists of a natural gas turbine/generator equipped with a heat recovery steam generator (HRSG) to capture waste heat from the turbine exhaust. The HRSG 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 an HRSG.

For Idaho Power's cost estimates and operating parameters for a CCCT resource, see the Supply-Side Resource section of *Appendix C—Technical Report* of the 2021 IRP.

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 and can assist in the integration of VERs.

Several natural gas SCCTs have been brought online in the region in the past two decades, primarily in response to the regional energy crisis of 2000 to 2001. High electricity prices combined with persistent drought during 2000 to 2001, as well as continued summertime peak-load growth, created an appetite for generation resources with low capital costs and relatively short construction lead times.

Idaho Power currently owns and operates approximately 430 MW of SCCT capacity. As peak summertime electricity demand continues to grow within Idaho Power's service area, SCCT generating resources remain a viable option to meet peak load during critical high-demand periods when the transmission system is constrained. 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* of the 2021 IRP.

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engine (RICE) 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.

For Idaho Power's cost estimates and operating parameters for RICE facilities, see the Supply-Side Resource section of *Appendix C—Technical Report* of the 2021 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 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 2021 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 by which a coal power plant can be converted to natural gas. The less common way is to fully retire the existing coal facility and replace it with a CCCT natural gas facility. The more common method is to convert the existing steam boiler to utilize natural gas instead of coal.[19] In either case, the conversion process can create numerous benefits, including reduced emissions, reduced plant O&M expenses, reduced capital costs, and increased flexibility.

For purposes of the 2021 IRP, Idaho Power has not modeled the first method in which a specific coal facility is replaced by a CCCT.

As a minority owner of the Jim Bridger facility, Idaho Power is aligning its modeling of the Jim Bridger plant with PacifiCorp's 2021 IRP by assuming that units 1 and 2 convert from coal to natural gas in 2024, or they are exited by the company. Idaho Power did not force the model to convert units 1 and 2 but instead allowed the LTCE model to either exit the units or convert them to natural gas.

Hydrogen Retrofit Opportunities

Hydrogen can be used to generate power with existing natural gas burning facilities with a retrofit. The production of hydrogen gas through electrolysis (a process that separates hydrogen from water with oxygen as a byproduct) using excess renewable energy is becoming more popular and costs are decreasing. There are opportunities to retrofit existing facilities to support fueling with a hydrogen blend to reduce greenhouse gas emissions. A full conversion can also be considered once larger quantities of hydrogen are commercially available. Idaho Power is monitoring these developments and will continue to evaluate opportunities associated with hydrogen.

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 technologies in the IRP process. Due to the Idaho National Laboratory (INL) site located in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor (SMR) could be built on the site. In September 2020, the Nuclear Regulatory Commission (NRC) issued its final safety evaluation report of NuScale Power's SMR design, with the full design certification pending. NuScale's current timeline would have their first reference plant online and fully operational by 2030 at INL. Idaho Power continues to monitor the advancement of SMR technology and will evaluate it in the future as the NRC reviews proposed SMR designs.

[19] https://www.eia.gov/todayinenergy/detail.php?id=44636

For the 2021 IRP, a 77-MW SMR was analyzed. Compared to typical reactor designs, SMRs offer numerous 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* of the 2021 IRP.

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 historic-low natural gas prices have made it imprudent to consider building new conventional coal generation resources.

No new coal-based energy resources were modeled as part of the 2021 IRP.

Storage Resources

RPSs have spurred the development of renewable resources in the Pacific Northwest to the point where there is an oversupply of energy during select times of the year. Mid-C wholesale market prices for electricity continue to remain relatively low. The oversupply issue has grown to the point where, at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to be negative.

As increasing amounts of VERs continue to be built within the region, the value of an energy storage project increases. There are many energy storage technologies at various stages of development, such as hydrogen storage, compressed air, flywheels, battery storage, pumped hydro storage, and others. The 2021 IRP considered a variety of energy-storage technologies and modeled battery storage and pumped hydro storage.

Energy storage can provide numerous grid services in both short (less than 1 hour) and medium duration (between 1 hour and 8 hours). 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, transmission and distribution deferral, and shaping for VERs.

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-based, which accounted for more than 90% of large-scale battery storage projects in the United States[20] as of the end of 2019. Li-ion based chemistries provide significant advantages compared to other battery-storage technologies commercially available today. Those advantages include high cycle efficiency, high cycle life, fast response times, and high energy density. Although other chemistries—such as sodium-sulfide, nickel-cadmium, and lead-acid—have been installed and used for a variety of applications on the grid, their use has been limited due to numerous technical and financial reasons. It is for the reasons above that Idaho Power has focused on and modeled Li-ion storage over other technologies in the 2021 IRP. Idaho Power will continue to observe and evaluate the changing storage technology landscape.

Li-ion-based energy storage devices, like nearly any technology, can present potential safety concerns, and there have been several high-profile incidents of dangerous battery malfunctions.[21] [22] [23] That said, the battery storage industry is making strides to reduce the potential dangers posed by lithium-based storage technologies, and it is reasonable to believe technological improvements will increase the safety of these options in the future.

Costs for battery systems have experienced significant cost reductions[24] and provide numerous grid services. Idaho Power will continue to monitor price trends and scalability of this technology in the coming years.

The average ELCC value applied to future storage projects was 87.5% for 4-hour and 97% for 8-hour.

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* of the 2021 IRP.

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[20] https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf

[21] https://www.aps.com/en/About/Our-Company/Newsroom/Articles/Equipment-failure-at-McMicken-Battery-Facility

[22] https://www.faa.gov/airports/airport_safety/certalerts/media/part-139-cert-alert-16-08-samsung-galaxy-note-7-ban.pdf

[23] https://www.cnbc.com/2021/07/23/gm-issues-second-recall-of-chevy-bolt-evs-after-vehicles-catch-fire.html

[24] https://www.eia.gov/todayinenergy/detail.php?id=45596#

Pumped-Hydro Storage

Pumped-hydro storage is a type of hydroelectric power generation that is capable of consuming electricity during times of low value and generating electricity during periods of high value. The technology stores potential energy by pumping water from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

Typical round-trip cycle efficiencies are between 75% and 82% for pumped-hydro storage. The efficiency of a pumped-hydro storage facility is dependent on system configuration and site-specific characteristics. Pumped-hydro storage projects are often large and become more feasible where large amounts of storage are identified as a system need. Due to the region's increasing VER penetration, and the ancillary services required, Idaho Power will continue to monitor the viability of pumped-hydro storage projects.

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* of the 2021 IRP.

IRP REPORT:

DEMAND-SIDE RESOURCES

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 leading resource in IRPs since 2004, providing average cumulative system load reductions of over 289 aMW by year-end 2020, while demand response programs in the past have brought significant peaking resources, with 380 MW of available capacity to serve system demand. Historically, energy efficiency potential resources have first been forecasted and screened for cost-effectiveness, then all available energy efficiency potential resources are included in the IRP before considering new supply-side resources. As part of the 2021 IRP, the company convened an energy efficiency working group, which consisted of interested members of the IRPAC and the Energy Efficiency Advisory Group. Based on input from this group, two approaches were used to include energy efficiency potential in the 2021 IRP.

Energy efficiency is estimated to reduce system peak by 440 MW. Also included in the Preferred Portfolio is 300 MW of nameplate summer capacity reduction from demand response plus an additional 100 MW of demand response by the end of the planning timeframe.

Energy Efficiency Forecasting—Energy Efficiency Potential Assessment

For the 2021 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 2021 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, which is increased for higher-cost measures.

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 extra bundles of achievable technical energy efficiency and their costs in the AURORA model in the 2021 IRP.

Technically Achievable Supply Curve Bundling

Based on input from the efficiency working group, an approach was established that bundles 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 applies a market adoption factor intended to estimate those customers likely to participate in programs incentivizing more efficient processes and/or equipment, similar to the approach used when forecasting achievable potential.

Four bundles of energy efficiency measures were created that were grouped by summer or winter measures, as well as a high- and low-cost bundle for each season. Whether a measure belonged in the summer or winter bundle depended on the ratio of peak winter to summer kW determined by the measure's load shapes at the hour of seasonal peak need. The bundles are sized to be large enough to be used in AURORA, but small enough to keep the average levelized cost reflective of the costs of the measures associated with it.

After bundle creation, the bundles were loaded into the AURORA software with a 'nameplate' capacity (peak kW) and an 8,760-hour load shape that contained the percentage of peak demand for each hour of the year. A levelized cost was given for each bundle for each year. Because energy efficiency bundles may be necessary at different times, each bundle was modeled as its own resource for every year of the planning period. This gave the model the ability to select energy efficiency at any point in the planning period and keep the energy efficiency program active for as long as necessary. Therefore, the energy efficiency bundles were evaluated for every year in the model and activated or deactivated accordingly. If more than one year of a bundle is selected, the values are additive. For example, if the summer low-cost bundle is selected in 2023 at 3.6 MW and it is selected again in 2024, but is no longer needed in 2025, that bundle contributes 3.6 MW in 2023 and 7.2 MW in 2024 continuing through the remainder of the planning period. Once a bundle is selected, its contribution was held in the model throughout the remainder of the 20-year period. 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	3.6	$103
Summer High Cost	21.7	$596
Winter Low Cost	12.6	$66
Winter High Cost	5.8	$325

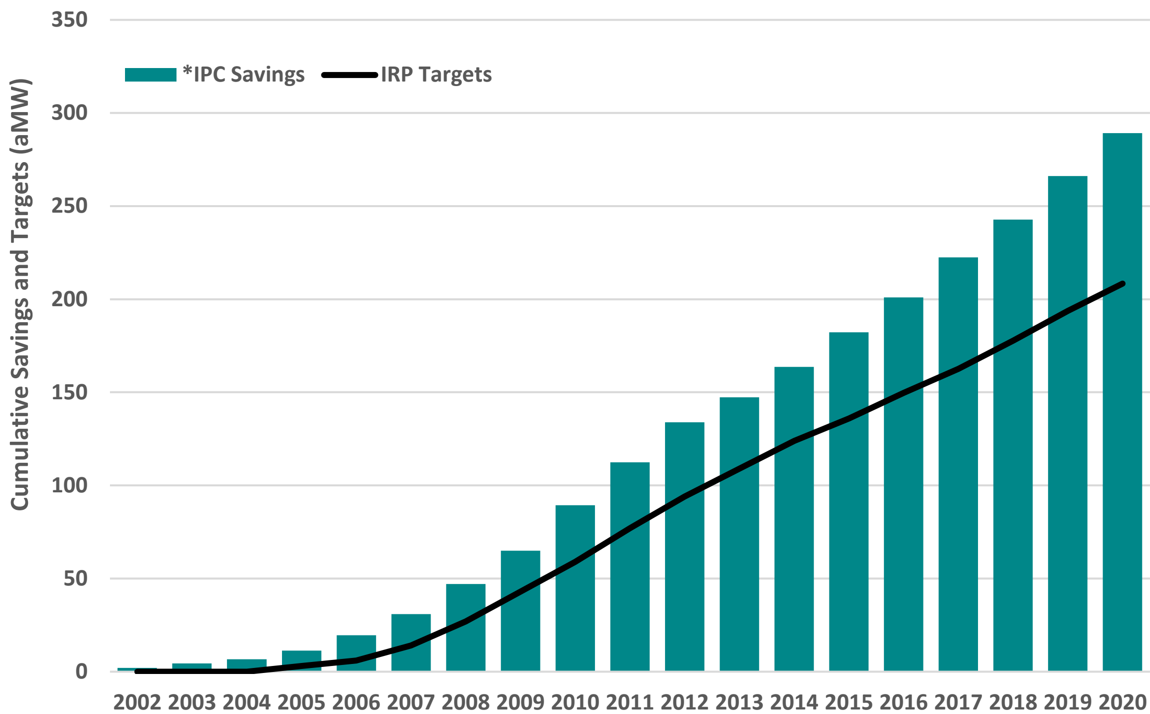
Future Energy Efficiency Potential

The 20-year energy efficiency potential included in the 2021 IRP increased from 234 aMW in the 2019 IRP to 300 aMW in the 2021 IRP. System on-peak potential from energy efficiency also increased from 367 MW to 376 MW from the 2019 IRP to the 2021 IRP. Most of the increase in energy efficiency potential was due to a change in the cost-effectiveness test.
Previously, the Total Resource Cost (TRC) was used, but beginning in 2020 the UCT was used. Typically, the UCT provides a lower threshold for cost-effectiveness relative to the TRC, allowing for additional energy efficiency to be cost-effective.

DSM Program Performance and Reliability

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 289 aMW, or approximately 2.3 million MWh, of reduced supply-side energy production to customers through 2020. Figure 6.1 shows the cumulative annual growth in energy efficiency savings from 2002 through 2020, along with the associated IRP targets developed as part of the IRP process since 2004.



***** Idaho Power 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 and low-cost resource. Table 6.2 shows the 2020 year-end program results, expenses, and corresponding benefit-cost ratios.

Table 6.2 Total energy efficiency portfolio cost-effectiveness summary, 2020 program performance

Customer Class	2020 Savings (MWh)*	UCT ($000s)	Total Utility Benefits ($000s) (NPV**)	UCT: Benefit/ Cost Ratio	UCT Levelized Costs (cents/kWh)
Residential	37,302	$9,626	$15,792	1.6	2.6
Industrial/commercial	130,633	$24,898	$79,127	3.2	1.9
Irrigation	12,884	$3,402	$13,645	4.0	2.5
Total* **	**180,818**	**$40,052**	**$108,563**	**2.7**	**2.1**

* Values may not add to 100% due to rounding

** 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: Excludes market transformation program savings.

Energy Efficiency Reliability

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 (RTF) 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 RTF or other sources. Evaluated savings are expressed through a realization rate (reported savings divided by evaluated savings). Realized savings of programs evaluated between 2019 and 2020 ranged between 97% and 100%. The savings-weighted-realized-savings average over the same period is 99%.

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is composed 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. During the 2020 summer season, Irrigation Peak Rewards participants contributed 82% of the total potential demand-reduction capacity, or 298 MW. More details on Idaho Power's demand response programs can be found in the *Demand-Side Management 2020 Annual Report*.

Table 6.3 2020 demand response program capacity

Program	Customer Class	Reduction Technology	2020 Total Demand Response Capacity (MW)	Percent of Total 2020 Capacity*
A/C Cool Credit	Residential	Central A/C	32	9%
Flex Peak Program	Commercial, industrial	Various	36	10%
Irrigation Peak Rewards	Irrigation	Pumps	298	82%
Total			**366**	**100%**

*Values may not add to 100% due to rounding.

Figure 6.2 shows the historical annual demand response program capacity between 2004 and 2020. 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 in the 2013 IRP.

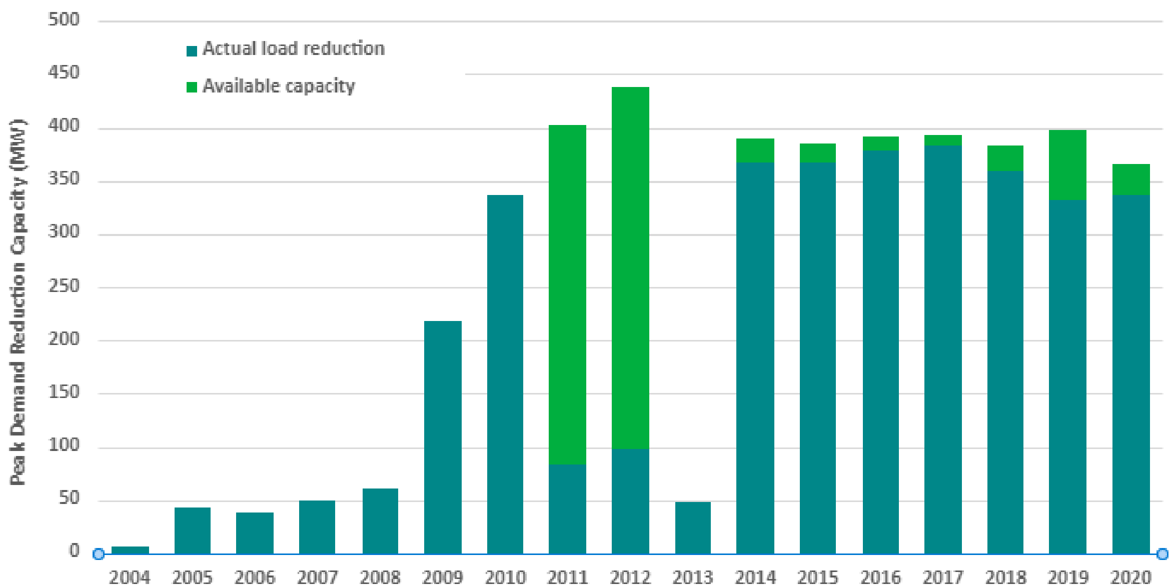


Figure 6.2 Historic annual demand response program performance

Demand Response Resource Potential

In the 2019 IRP, demand response from all programs was committed to provide 380 MW of peak capacity during June and July throughout the IRP planning period, with a reduced amount of program potential available during August.

As part of the 2021 IRP's rigorous examination of the potential for expanded demand response, Idaho Power utilized a Northwest Power and Conservation Council (NWPCC) assessment of DR potential for the Northwest region to determine the DR potential that may be available in Idaho Power's service area. Based on this assessment, Idaho Power estimated 584 MW of DR potential in its service area and concluded that any needed capacity from demand response would be shifted to later hours of the day than what the current DR programs were designed for.

Efforts to redesign each of Idaho Power's current programs to better align with system needs took place over the summer and early fall of 2021. Based on the results of the analysis, Idaho Power submitted filings with both the IPUC and OPUC to modify the program parameters. Based on these proposed changes to the programs, Idaho Power assumed there would likely be a reduction in participation, so starting in 2022, the 380 MW nameplate capacity was adjusted to 300 MW.

The NWPCC assessment of DR also included a potential associated with pricing programs, notably time-of-use (TOU) and critical peak pricing (CPP). The company has existing TOU offerings in both its Idaho and Oregon jurisdictions. The company's Idaho offering was initially developed in 2005 and now has approximately 1,000 customers enrolled. The company implemented TOU in its Oregon jurisdiction 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 what venue to report TOU performance. The company believes it may be most appropriate to report ongoing TOU pilot performance and any changes to the offering in its annual DSP report, beginning with the summer 2022 report.

In summary, DR was evaluated in the 2021 IRP modeling process by using the 584 MW of DR potential with an estimate of 300 MW of capacity from the modified DR programs. Therefore, a maximum of approximately 280 additional MW of DR (584 MW minus 300 MW, rounded down) was available for selection in the AURORA model when analyzing the future load and resource balance. The additional DR capacity was divided into 20-MW bundles and available for selection up to the threshold. Idaho Power will continue to evaluate the DR potential in its service area with each IRP planning cycle.

T&D Deferral Benefits

Energy Efficiency

For the 2019 IRP, Idaho Power determined the T&D deferral benefits associated with energy efficiency by performing an analysis to determine how effective energy efficiency would be at deferring transmission, substation, and distribution projects. To perform the analysis, the company used historical and projected investments over a 20-year period from 2002 to 2021. Transmission, substation, and distribution projects at various locations across the company's system were represented. The limiting capacity (determined by distribution circuit or transformer) was identified for each project, along with the anticipated in-service date, projected cost, peak load, and projected growth rate.

Varying amounts of incremental energy efficiency were used and spread evenly across customer classes on all distribution circuits. 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 for each year in the 20-year forecast of incremental achievable energy efficiency. The calculated T&D deferral values ranged from $6.52 per kW-year to $1.40 per kW-year based on a forecasted incremental reduction in system sales of between 0.86% to 0.43% from energy efficiency programs. The 20-year average was $3.74 per kW-year. These values are then used in the calculation of energy efficiency cost-effectiveness.

For the 2021 IRP, Idaho Power has recognized an opportunity to align the timing of the T&D deferral analysis for energy efficiency and the energy efficiency potential assessment (used to calculate the cost-effective measures). The calculated values are used in the energy efficiency potential assessment which occurs a year before a typical IRP analysis (meaning the energy efficiency potential assessment had already been conducted for the 2021 IRP using the values from the 2019 IRP). Idaho Power plans to update the T&D deferral analysis for energy efficiency in the spring of 2022 so that new values will be implemented as part of the 2023 IRP energy efficiency potential assessment.

Distribution System Planning

Although Idaho Power has always conducted distribution system planning (DSP), in March 2019 the OPUC initiated an investigation into distribution system planning 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."[25]

Over nearly two years, OPUC staff, stakeholders, and utilities have engaged in workshops and seminars to discuss distribution system planning 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. On October 15, 2021, Idaho Power filed its Distribution System Plan Part I report with the OPUC in docket UM 2196. Within the report the company identified how the DSP and resource planning processes can inform and/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. Distribution system planning 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 DERs in the IRP resource stack. To the extent that IRPs identify DER in the first two to four years of the IRP Action Plan, local load forecasts and the distribution plan would be adjusted based on the anticipated peak demand reduction.

Importantly, however, 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, any DER identified in the IRP does not specify location. The DSP is needed to inform the locational value (or cost) of DER on Idaho Power's system. With these considerations, the IRP and DSP are linked, and the results of either informs the other in an iterative process.

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

An IDACORP Company

IRP REPORT:

TRANSMISSION PLANNING

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 coal 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 the environment and 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 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 OATT 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 Canada, BPA, Chelan County PUD, Grant County PUD, Idaho Power, 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: www.northerngrid.net.

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 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.

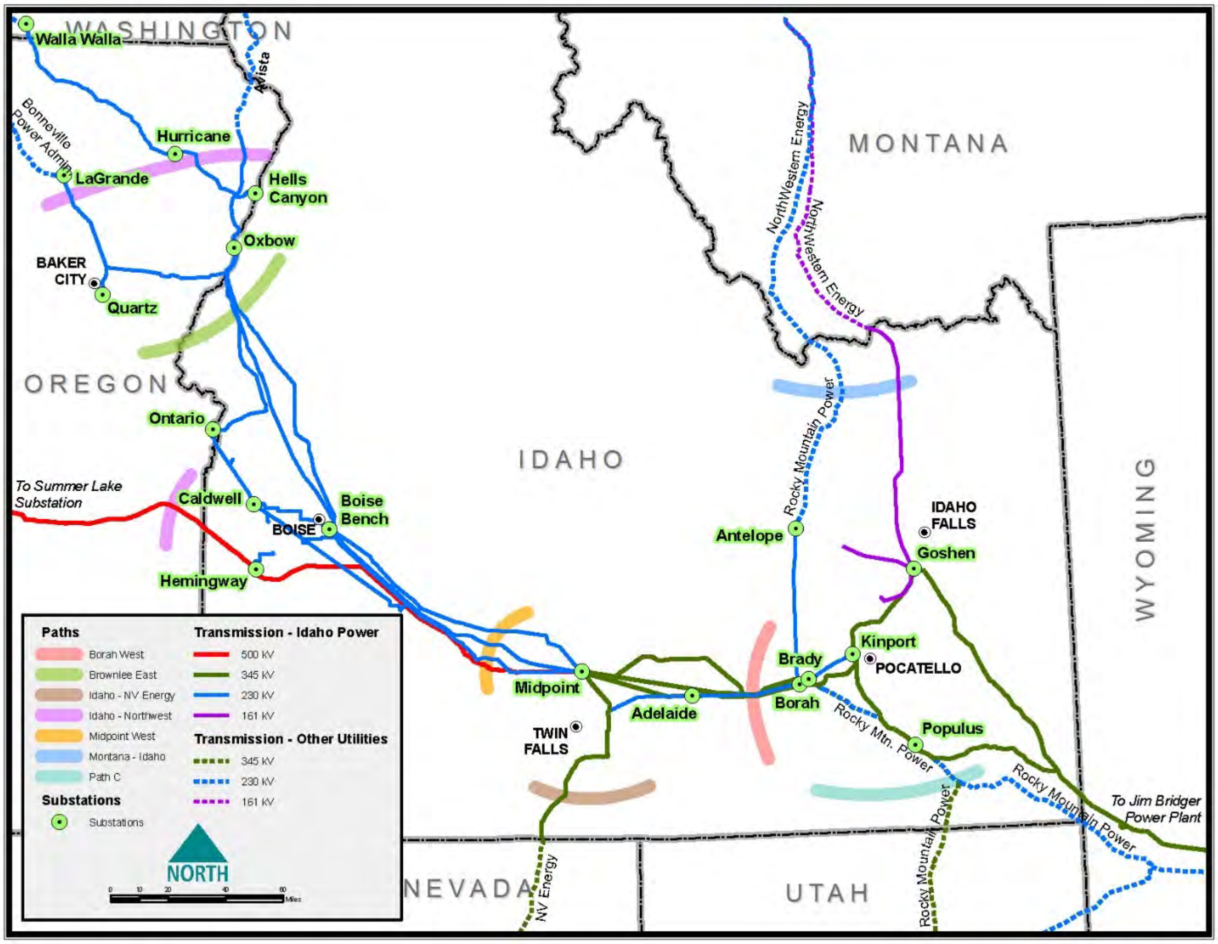


Figure 7.1 Idaho Power transmission system map

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 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 additional 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. Idaho Power continues to reserve capacity on internally controlled lines for facilitating external market purchases, but with the increased demand for firm transmission, the company has experienced near-term difficulty in reserving transmission on third-party controlled transmission between the Mid-C market hub and the Idaho to Northwest path. The company has made efforts to reserve transmission capacity on third-party systems since the 2019 IRP (further discussed in *Appendix D*).

Brownlee East Path

The Brownlee East transmission path 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.

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 consists of the Antelope–Anaconda 230-kV and Goshen–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 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 is internal to Idaho Power’s system and is jointly owned between Idaho Power and PacifiCorp. 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 also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production move 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. Idaho Power owns 1,710 MW of the path, and PacifiCorp owns 1,090 MW of the path (all on the Midpoint–Hemingway 500-kV line). The path is composed of 500-kV, 230-kV, and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. Like the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. 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 is the 345-kV Midpoint–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 utilizes approximately 130 MW.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, 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, 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 east to west; 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 capability (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–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).

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, identified in 2006, has evolved into what is now B2H. The project, which is expected to provide a total of 2,050 MW of bidirectional capacity[26], 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 *s*ubstation in southwest Idaho. The new line will provide many benefits, 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
- Flexibility to integrate renewable resources and more efficiently implement advanced market tools, such as the EIM

[26] 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.

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 since 2009. The 2017 IRP was the first IRP to include construction activities in the near-term Action Plan and the 2019 IRP also included construction activities in the near-term Action Plan. The 2017 IRP and 2019 IRP near-term Action Plans, including B2H construction related activities mentioned within, were acknowledged by both the Idaho and Oregon PUCs.

Given the importance of the B2H project, the company will provide an IRP appendix, anticipated in the first quarter of 2022. *Appendix D—Transmission Supplement* will provide granular detail regarding Idaho Power's need for the project, co-participants, project history, benefits, and risks.

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 ten years 2010–2019. The B2H project is similarly a major component of the 2020–2021 NorthernGrid regional transmission plan, published in December 2021. Regional transmission planning efforts are widely regarded as producing efficient and cost-effective pathways to meet the load and resource needs of a given region.

The B2H project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and save consumers money. In a November 17, 2017, United States Department of the Interior press release,[27] B2H was held up as "a Trump Administration priority focusing on infrastructure needs that support America's energy independence…" The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it…"

B2H Value

Idaho Power in the 2021 IRP requests acknowledgement of B2H based on the company owning 45% of the project. This ownership share, which represents a change from Idaho Power's 21% share in the 2019 IRP, is the result of negotiations among Idaho Power, PacifiCorp, and BPA. Under such a structure, Idaho Power would absorb BPA's previously assumed ownership share in exchange for BPA entering into a transmission service agreement with Idaho Power.

[27] blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho

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

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

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

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

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

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

Project Participants

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

Table 7.2 B2H capacity and permitting cost allocation

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

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

Table 7.3 B2H capacity allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	750	0	300
Capacity (MW) east to west	182	0	818
Permitting cost allocation	45%	0%	55%

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

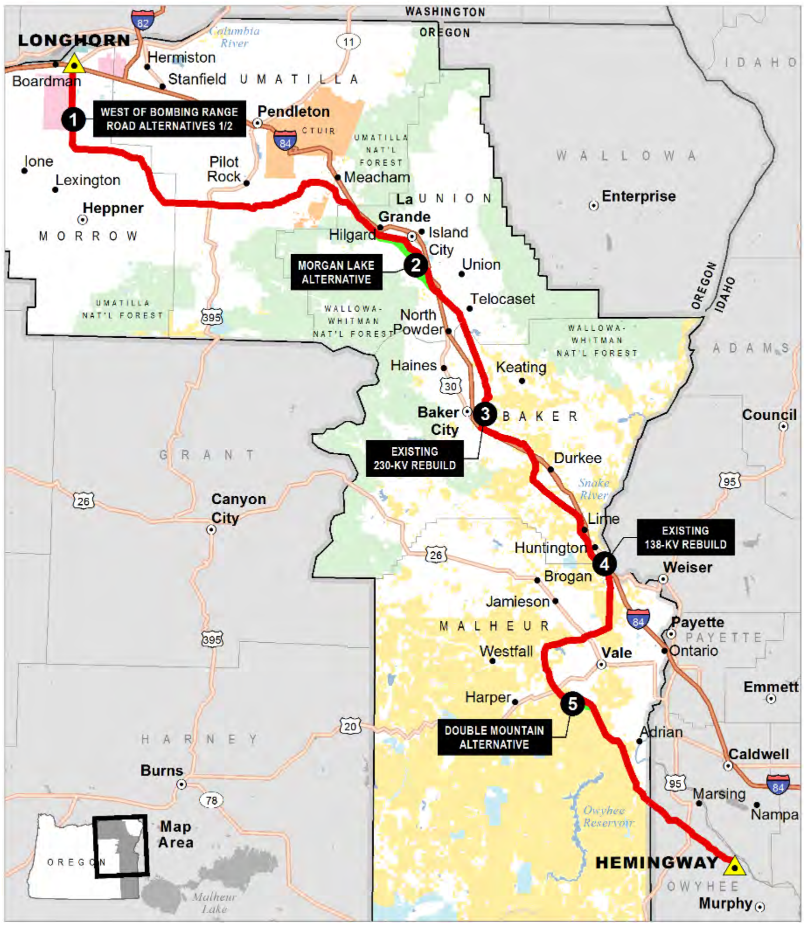


Figure 7.2 B2H route submitted in 2017 Oregon Energy Facility Siting Council (EFSC) Application for Site Certificate

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 (USFS), United States Navy, and the Energy Facilities Siting Council of Oregon (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 USFS 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 (pASC) to EFSC in February 2013 and submitted an amended pASC in summer 2017. The amended pASC 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 has been initiated and is being presided over by an EFSC-appointed Administrative Law Judge. Idaho Power currently expects the EFSC to issue a final order and site certificate in the second half of 2022. Permitting in Idaho will consist of a Conditional Use Permit issued by Owyhee County.

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

Next Steps

With the issuance of a Proposed Order, sufficient route certainty exists to begin preliminary construction activities. These activities include, but are not limited to, the following:

- Geotechnical surveys
- Detailed ground surveys (light detection and ranging [LiDAR] surveys)
- Sectional surveys
- Right-of-way activities
- Detailed design
- Construction bid package development

After the B2H project receives a Final Order and Site Certificate from EFSC, construction activities will commence. Construction activities include, but are not limited to, the following:

- Long-lead material acquisition
- Transmission line construction
- Substation construction or upgrades

The specific timing of each of the preliminary construction and construction activities will be coordinated with the project co-participants. Additional project information is available at boardmantohemingway.com.

B2H Cost Treatment and Modeling in the IRP

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. 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, 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 2021 IRP, Idaho Power continued to model expected incremental third-party wheeling revenues as a reduction in costs ultimately benefitting 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 2021 IRP, Idaho Power modeled B2H assuming the company has a 45% ownership interest and 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 an additional cost offset for IRP portfolios with B2H.

In IRP modeling, Idaho Power assumes a 45.45% share of the direct expenses of B2H, plus an Allowance for Funds Used During Construction (AFUDC) cost. Total Cost Estimate: $485 million, which includes $35 million in local interconnection upgrades.

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 November 2020.

Idaho Power has a one-third 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 would provide a total of 3,000 MW of additional transfer capacity. 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 is a major component of the 2020–2021 NorthernGrid regional transmission plan. 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 Cost Treatment and Modeling in the 2021 IRP

Similar to the B2H project, Idaho Power is working with PacifiCorp to develop the Gateway West transmission project. 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 integrated 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 two primary transmission constraints: 1) transmission capacity between the Magic Valley and Treasure Valley (Midpoint West), and 2) transmission capacity between the Mountain Home area, and the Treasure Valley (Boise East). Given identified coal unit exits at the Jim Bridger and North Valmy power plants, the company can repurpose significant Midpoint West capacity to integrate resources on the east side of the Idaho Power transmission system. However, the Boise East path remains constrained.

For the 2021 IRP, the company modeled a Gateway West segment, the Midpoint to Hemingway #2 500-kV line (segment 8), as being phased in with two separate transmission projects. The transmission sub-segments were modeled as being triggered coincident with different quantities of net incremental resource additions. The first sub-segment of Gateway West is required following the incremental addition of about 900 to 1,300 MW of resources. This sub-segment is the section from Mountain Home to the Treasure Valley, with Idaho Power modeling the line as being constructed as a 500-kV line but operated at 230 kV.

The second sub-segment of Gateway West is required following 700 MW of additional incremental resources (1,600-2,000 MW in total). This sub-segment connects the Magic Valley to Mountain Home, constructed and operated at 500 kV, with the assumed conversion of the first sub-segment of the line to 500 kV as well.

To determine a cost-estimate for these sub-segments, the company utilized costs associated with its Gateway West federal permit, transmission cost-per-mile estimates for B2H, and 230-kV substation estimates. The total cost estimate for Idaho Power is $176 million, plus local interconnection upgrades totaling $35 million, if necessary.

Nevada Transmission without North Valmy

The Idaho–Nevada transmission path is co-owned by Idaho Power and NV Energy. After the anticipated Idaho Power exit from the North Valmy unit, the existing Midpoint-Valmy transmission agreement between Idaho Power and NV Energy will likely be terminated. Idaho Power will own and control the bi-directional transmission capacity from the

Idaho–Nevada border to Midpoint and NV Energy will own and control the bi-directional transmission capacity from North Valmy to the Idaho–Nevada border.

With this assumption, import availability was evaluated on the transmission path as part of the 2021 study evaluating Valmy Unit 2 exit dates. The analysis determined that no long-term firm transmission is available on third party transmission across the NV Energy system from southern market energy hubs to the Idaho Power border. Given the lack of long-term firm transmission availability south of NV Energy, the transmission path capacity into the Idaho Power system is not included within Idaho Power's capacity planning margin. The path, however, is expected to continue to be heavily utilized for real-time transactions by the Energy Imbalance Market.

Southwest Intertie Transmission Project-North

The Southwest Intertie Transmission Project-North (SWIP-North) is a proposed 275-mile 500-kV transmission project being developed by Great Basin Transmission, LLC which is an affiliate of LS Power. The SWIP-North connects Idaho Power's Midpoint substation near Twin Falls, 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 segment between Robinson Summit and the Harry Allen substation in the Las Vegas, Nevada, area. The two projects together are the combined SWIP project. The combined SWIP project is expected to have a bi-directional WECC-approved path rating of approximately 2,000 MW.

The addition of the SWIP-North segment would unlock additional capacity on the existing ON Line that connects northern and southern Nevada. Contractual ownership of capacity on SWIP-North would provide capacity rights to and from the Harry Allen substation in the Las Vegas area. The Harry Allen substation is connected to the California Independent System Operator (CAISO) via the newly constructed DesertLink 500-kV line. The substation is also near the desert southwest market hub, Mead. Idaho Power's potential participation in the project could provide the company transmission access—past congestion on NV Energy's system—from the desert southwest market and CAISO directly to Idaho Power. Figure 7.4 shows the SWIP-North Preliminary Route and the locations of the ON Line and DesertLink 500-kV lines to the south.

To determine a cost-estimate for SWIP-North, the company used publicly available cost data for similar lines recently constructed in Nevada and assumed that Idaho Power would own a 200-MW share of the south-to-north capacity. The SWIP-North project was not considered for inclusion in the company's Preferred Portfolio in the 2021 IRP due to uncertainty related to total project viability and available partners. The project was evaluated to determine whether further exploration is warranted. Given the results detailed in Chapter 11, the company plans to engage in discussions with the SWIP-North project developer to perform a more detailed evaluation in future IRPs.

Total Cost Estimate (200 MW share): $133 million with a pre-summer 2025 in-service date.

Figure 7.4 SWIP-North Preliminary Route

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 7.4. The company assumed all resources

Transmission lines under construction at the Hemingway substation.

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.

Table 7.4 Transmission assumptions and requirements

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions
Biomass indirect—anaerobic digester	35	Distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	Connection to distribution feeder.
Geothermal (binary-cycle)—Idaho	30	Raft River area location; displaces equivalent MW of portfolio resources in same region.	Requires 5-mile, 138-kV line to nearby station with new 138-kV substation line terminal bay.
Natural gas—SCCT frame F class	170	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Connection to 230 kV ring bus.
Natural gas—reciprocating gas engine Wärtsilä 34SG	55	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at 230-kV Rattlesnake Substation.
Natural gas—CCCT (1x1) F class with duct firing	300	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at 230-kV Rattlesnake Substation.
Nuclear—SMR	77	Tie into Antelope 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise.	Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at Antelope Substation. New 55-mile 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation.
Pumped storage—new upper reservoir and new generation/ pumping plant	250	Anderson Ranch location; displaces equivalent MW of portfolio resources in same region.	18-mile, 230-kV line to connect to Rattlesnake Substation.
Solar PV—utility-scale 1-axis tracking	100	Magic Valley location; displaces equivalent MW of portfolio resources in same region.	1-mile, 230-kV line and associated stations equipment.
Wind—Idaho	100	Location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region.	5-mile, 230-kV transmission from Midpoint Substation to project site.
Wind—Wyoming	100	Location within 5 miles of Jim Bridger–Populus 345-kV transmission line	5-mile, 345-kV transmission from Jim Bridger—Populus line to project site

IRP REPORT:

PLANNING PERIOD FORECASTS

8. PLANNING PERIOD FORECASTS

Chobani plant near Twin Falls, Idaho.

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

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

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2021 IRP. A more detailed discussion on these topics is included in *Appendix A—Sales and Load Forecast*.

Load Forecast

Each year, Idaho Power prepares a forecast of sales and demand of electricity using the company's electrical T&D network. 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 (A/C) in June, July, and August. 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 2021 IRP.

The anticipated average energy (average load) and anticipated peak-hour demand forecast represent Idaho Power's most probable outcome for load requirements during the planning period. In addition, Idaho Power prepares other probabilistic load forecasts that 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 1.4% (over the period 2021 through 2040) comprises a residential load growth of 0.8%, a commercial load growth of 0.9%,

an irrigation load growth of 0.6%, an industrial load growth of 1.6%, and an additional firm load growth of 6.3%.

The number of residential customers in Idaho Power's service area is expected to increase 1.9% annually from 491,229 at the end of 2020 to nearly 719,500 by the end of the planning period in 2040. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 0.8% average annual residential load-growth rate over the forecast term.

Significant factors that influenced the outcome of the 2021 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 case 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 2021 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service-area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. The state of Idaho had the highest residential population growth rate of any state in the United States over the past five years (ending 2020).
- Conservation impacts—including DSM 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. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., demand response is treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*. Additional impacts from on-site generation customers and electric vehicles are included as well.
- Although interest from large customers has been robust, there is some uncertainty associated with these industrial and special contract customers due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an uncertain magnitude of the energy and peak-demand requirements. The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment and/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 but 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 2021 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP Preferred Portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price forecast yields lower future prices. The retail prices are mostly lower throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.
- As discussed above, the response to the novel coronavirus influenced electric usage behavior across the major rate classes. These impacts tended to balance one another; e.g., increased residential consumption due to work-from-home behavior was offset by decreased use from office and other commercial facilities. While these impacts continue to play out in decreasing importance, the impact on the long-term forecast horizon is inconsequential.

Weather Effects

The anticipated 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. 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 abnormal weather—the 70th- and 90th-percentile load forecasts. Seventieth-percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth-percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

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. As Idaho Power has become 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 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 of any state in the United States over the past five years (ending 2020). The number of households in Idaho is projected to grow at an annual rate of 2% during the forecast period, with most of the population growth centered on the Boise City–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 2.6% 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 2021 IRP average annual system load forecast reflects continued improvement in the service-area's economy. The improving economic and demographic variables driving the 2021 forecast are reflected by a positive sales outlook throughout the planning period.

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 2021 IRP as annual system load growth over the planning period. There is an approximately 50% probability Idaho Power's load will exceed the expected-case forecast, a 30% probability of load exceeding the 70^{th}-percentile forecast, and a 10% probability of load exceeding the 90^{th}-percentile forecast. The projected 20-year compound annual growth rate in the expected case forecast and 70^{th}-percentile forecast is 1.4% during the 2021 through 2040 period. The projected 20-year average compound annual growth rate in the 90^{th} percentile forecast is 1.4% over the 2021 through 2040 period.

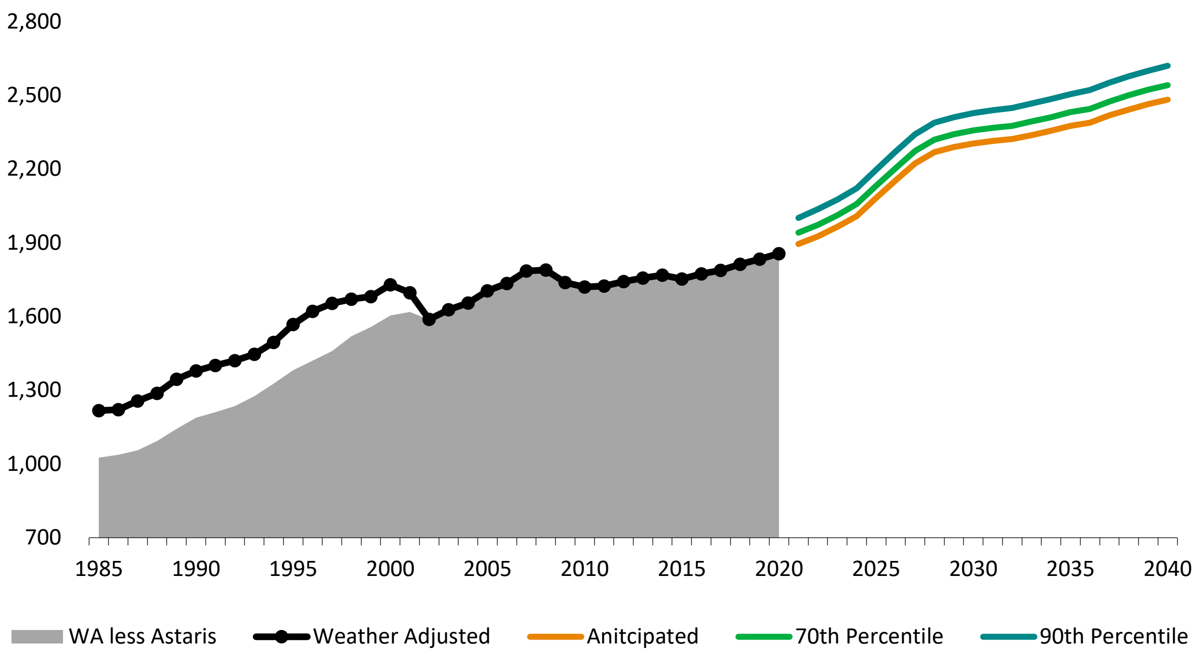


Figure 8.1 Average monthly load-growth forecast (aMW)

Table 8.1 Load forecast—average monthly energy (aMW)

Year	Anticipated	70th Percentile	90th Percentile
2021	1,895	1,941	2,001
2022	1,926	1,973	2,036
2023	1,965	2,012	2,076
2024	2,008	2,057	2,121
2025	2,082	2,132	2,197
2026	2,154	2,204	2,271
2027	2,223	2,274	2,342
2028	2,269	2,320	2,389
2029	2,289	2,341	2,411
2030	2,304	2,357	2,427
2031	2,314	2,368	2,439
2032	2,322	2,376	2,449
2033	2,338	2,393	2,466
2034	2,356	2,411	2,485
2035	2,375	2,431	2,505
2036	2,389	2,445	2,521
2037	2,418	2,475	2,551
2038	2,442	2,500	2,577
2039	2,464	2,522	2,600
2040	2,482	2,541	2,620
Growth Rate (2021–2040)	**1.4%**	**1.4%**	**1.4%**

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 special contracts.

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 A/C became standard in nearly all new home construction and new commercial buildings. 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 2021 IRP load forecast projects annual peak-hour load to grow by approximately 55 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance and are treated similarly to a supply-side resource.

Idaho Power's winter peak-hour load record is 2,527 MW, recorded January 6, 2017, at 9 a.m., matching the previous record peak December 10, 2009, at 8 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 three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th-percentile, 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.

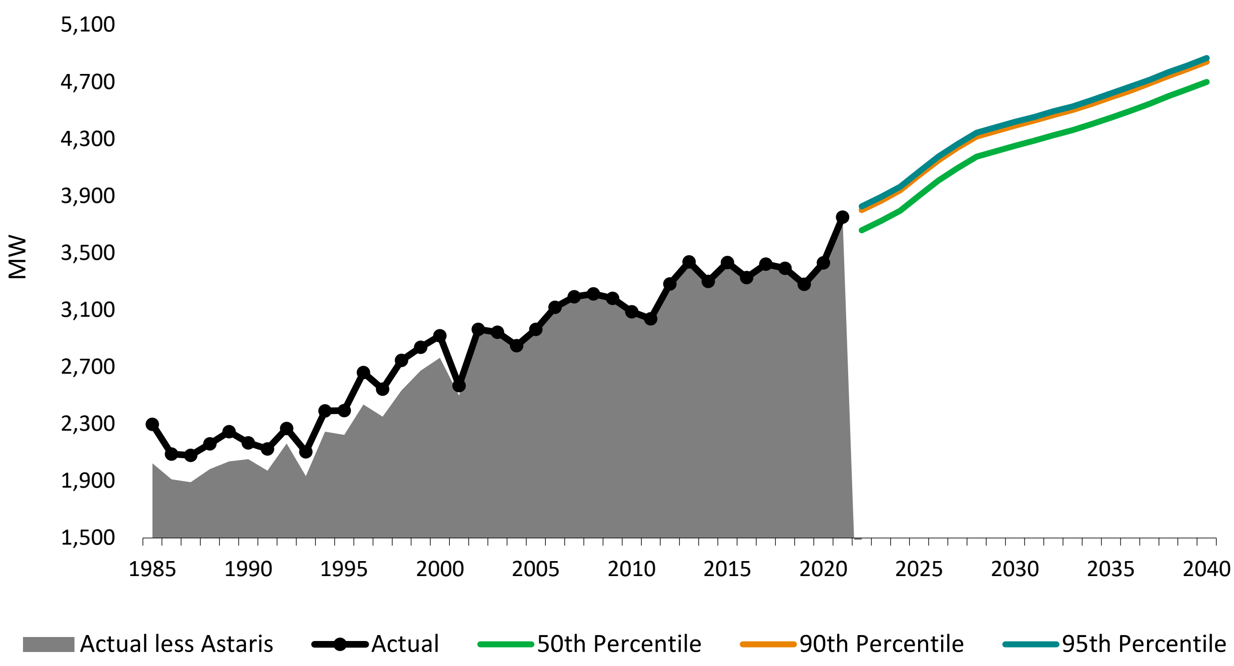


Figure 8.2 Peak-hour load-growth forecast (MW)

Table 8.2 Load forecast—peak hour (MW)

Year	50th Percentile	90th Percentile	95th Percentile
2020 (Actual)	3,430	3,430	3,430
2021	3,603	3,745	3,771
2022	3,659	3,801	3,827
2023	3,724	3,866	3,892
2024	3,797	3,939	3,965
2025	3,903	4,045	4,071
2026	4,007	4,149	4,175
2027	4,096	4,238	4,264
2028	4,176	4,318	4,344
2029	4,213	4,355	4,382
2030	4,252	4,394	4,421
2031	4,287	4,429	4,455
2032	4,326	4,468	4,494
2033	4,361	4,503	4,529
2034	4,405	4,547	4,573
2035	4,450	4,592	4,619
2036	4,497	4,639	4,666
2037	4,547	4,689	4,715
2038	4,599	4,741	4,767
2039	4,648	4,790	4,816
2040	4,700	4,842	4,868
Growth Rate (2021–2040)	**1.4%**	**1.4%**	**1.4%**

The median peak-hour load forecast predicts that peak-hour load will grow to 4,700 MW in 2040—an average annual compound growth rate of 1.4%. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.4%.

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 a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate state commission. A special contract 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 special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL, and an anticipated new special contract customer. These special-contract 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 5,000 to 6,000 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 their 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 Department of Energy’s (DOE) 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. It is the fifth-largest employer in the state of Idaho with an estimated 4,225 employees.

Anticipated Large Load Growth

Idaho Power’s anticipated load forecast includes new large load growth. This growth reflects industrial customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating in Idaho Power’s service area.

Generation Forecast for Existing Resources

Hydroelectric Resources

For the 2021 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 50^{th}-percentile means basin streamflows are expected to exceed the planning criteria 50% of the time and are expected to be worse than the planning criteria 50% of the time.


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

Idaho Power uses two modeling methods to develop future flows for the IRP. The first method is for accounting for surface water regulation in the system, this consists of two models built in the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES) 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 Enhanced Snake Plain Aquifer Model (ESPAM) to model aquifer management practices implemented on the ESPA. Modeling for the 2021 IRP used version 2.1 of the ESPAM model. The two modeling methods used in combination produce a normalized hydrologic record for the Snake River Basin from water year 1951 through 2018.
The record is normalized to account for specified conditions relating to Snake River reach gains, water management facilities, irrigation facilities, and operations. The 50^{th} percentile modeled streamflows are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2021 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 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 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 2021 IRP. The 2019 IRP modeling results for the 50th, 70th, and 90th percentiles are shown for reference only to benchmark the changes in hydrogeneration modeling between IRP cycles. As Figure 8.3 shows, the 2021 hydrogeneration distributions are very similar to the 2019 hydrogeneration 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 period.

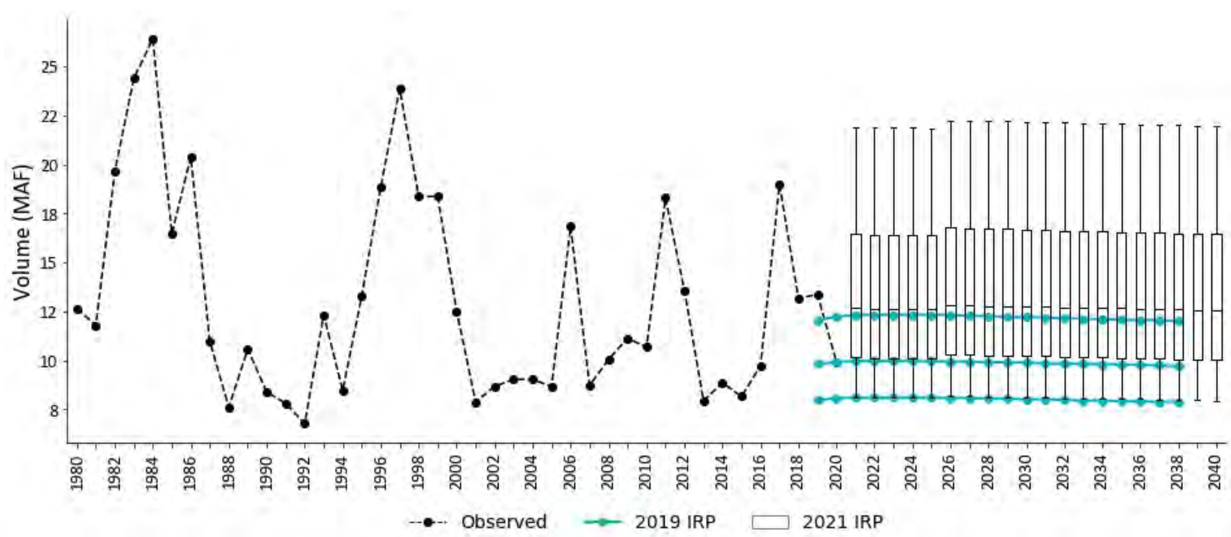


Figure 8.3 Brownlee inflow volume historical and modeled percentiles

Coal Resources

In the 2021 IRP, Idaho Power continued to analyze exiting from coal units before the end of their depreciable lives. The coal units continue to deliver generating capacity and energy during high-demand periods and/or during periods of high wholesale-electric market prices. Within the coal fleet, the Jim Bridger plant provides recognized flexible ramping capability enabling the company to demonstrate ramping preparedness required of EIM participants. Despite the system reliability benefits, the economics of coal plant ownership and operation remain challenging because of frequent low wholesale-electric market prices coupled with the need for capital investments for environmental retrofits. Moreover, the evaluation of exiting from coal unit participation is consistent with the company's glide path away from coal and goal to provide 100% clean energy by 2045.

Jim Bridger

The four Jim Bridger units are assumed to reach the end of their depreciable lives in 2034. Units 1 and 2 currently require Selective Catalytic Reduction (SCR) investment by year-end 2021 and 2022 for continued coal operation. The SCR investments on units 1 and 2 are not currently planned or included in the IRP analysis. PacifiCorp, in its 2021 IRP, has modeled these two units ceasing coal operations at the end of 2023 and converting to natural gas and operational in May of 2024.

For the 2021 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:

- Unit 1—Allowed to exit year-end 2023 or convert to natural gas. If converted to natural gas, the unit will operate through 2034.
- Unit 2—Allowed to exit between year-end 2023 and year-end 2026 or convert to natural gas as early as year-end 2023. If converted to natural gas, the unit will operate through 2034.
- Unit 3—Can exit no earlier than year-end 2025 and no later than year-end 2034.
- Unit 4—Can exit no earlier than year-end 2027 and no later than year-end 2034.

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 1 and 2 convert to natural gas, they are assumed to operate through their useful life and are exited in 2034.

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 as previously described. However, the AURORA modeling indicates removal of Jim Bridger units needs to be carefully evaluated because of potential heightened concerns about meeting regulating reserve requirements following their removal. For this reason, in the model, the first opportunity for each unit to exit is set two years following the previous units, except for units 1 and 2, which are allowed to exit or convert to natural gas operation in the same year. This spacing will give Idaho Power time to assess these system changes and ensure that a sufficient level of reliability is being achieved.

North Valmy

Idaho Power's participation in North Valmy Unit 1 ceased at year-end 2019. Exit from Unit 2 at year-end 2025 or earlier was evaluated as part of the AURORA capacity expansion modeling.

Natural Gas Resources

Idaho Power owns and operates four natural gas SCCTs and one natural gas CCCT, having combined nameplate capacity of 762 MW. The SCCT units are typically operated during peak-load events in the summer and winter. Idaho Power's CCCT, Langley Gulch, is typically dispatched more frequently and for longer runtimes than the SCCTs because of the higher efficiency rating of a CCCT. 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

To make continued improvements to the natural gas price forecast process, and to provide greater transparency, Idaho Power began researching natural gas forecasting practices used by electric utilities and local distribution companies in the region. Table 8.3 provides excerpts from IRP and avoided-cost filings, as an indication of the approaches used to forecast natural gas prices.

Table 8.3 Utility peer natural gas price forecast methodology

Utility	Gas Price Forecast Methodology
PacifiCorp 2019 IRP	PacifiCorp uses a blend of forward market prices and projections from third-party experts.
Avista Electric 2021 IRP	Avista uses a blend of forward market prices, forecast from a prominent energy industry consultant, and the EIA to develop the natural gas price forecast for this IRP.
Avista Gas 2021 Natural Gas IRP	Avista reviewed several price forecasts from credible sources and created a blended price forecast to represent an expected price.
PGE 2019 IRP	PGE derived the Reference Case natural gas forecast from market forward prices for the period 2020 through 2023 and the Wood Mackenzie long-term fundamental forecast for the period 2025 through 2040. A transition from the market price curve to Wood Mackenzie's long-term forecast is made by linearly interpolating for one year (2024). For the remaining years (2041 through 2050), PGE applies the rate of inflation to the 2040 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 IRP planning case natural gas price forecast.

The Platts forecast information below was presented by the vendor representative at the February 9, 2021, IRPAC meeting.

The third-party vendor uses the following inputs/techniques to develop its gas price forecast:

- Supply/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 2021 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 such as Russia and Qatar and the role of liquefied natural gas exports
- 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

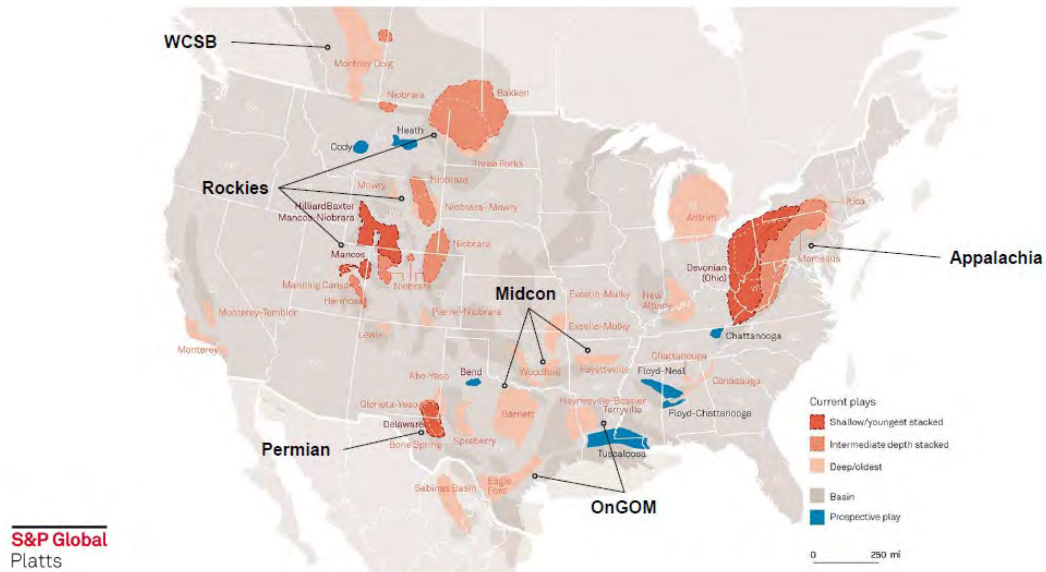


Figure 8.4 North American major gas basins

To verify the reasonableness of the third-party vendor's forecast, Idaho Power compared the forecast to Moody's Analytics, the United States Energy Information Administration (EIA), and the New York Mercantile Exchange (NYMEX) natural gas futures settlements. Based on a thorough examination of the forecasting methodology and comparative review of the other sources (i.e., Moody's, EIA, and NYMEX), Idaho Power concluded that the third-party vendor's natural gas forecast is appropriate for the planning case forecast in the 2021 IRP.

Platts' 2021 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. Sumas is where most of the fuel for Idaho Power's natural gas generation comes from.

Given that gas price forecasts are a significant driver of costs in the IRP process, Idaho power also relied on the EIA's Low Oil & Gas Supply forecast from their *Annual Energy Outlook 2021* to examine the impact of higher gas prices on the IRP. This forecast assumes lower oil and gas production, which creates a higher natural gas price. More details on the EIA forecast can be found in their *Annual Energy Outlook 2021*[28].

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 2019 IRP, Idaho Power believes that turnback pipeline capacity (existing contracts expiring without renewal) from Stanfield, Oregon, to Idaho could serve the need for natural gas generating capacity for up to 600 MW of installed nameplate capacity. Williams Northwest Pipeline has recently entered a similar capacity reservation contract with a shipper where a discount was offered (a 10-cent rate versus full tariff of 39 cents) for the first five years before the implementation of full tariff rate for the remainder of the term. Using this information, a rate was applied reflective of the capacity reservation contract rate discounted until the in-service date, and full tariff thereafter.

Idaho Power projects 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. The 600 MW limit, beyond which pipeline expansion is required, is derived from Northwest Pipeline's estimation of expected turnback capacity from Stanfield, Oregon, to Idaho as presented in Northwest Pipeline's fall 2019 Customer Advisory Board meeting. 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. Idaho Power applied this rate to potential natural gas generation types with an assumption of high-capacity factor (100% capacity coverage), medium capacity factor (33%), and low-capacity factor (25%). For the medium- and low-capacity factor plants, it is assumed that 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.

Analysis of IRP Resources

For the 2021 IRP, Idaho Power continues to analyze resources based on cost, specifically the cost of a resource to provide energy and peaking capacity to the system. In addition to the

[28] United States Energy Information Administration, *Annual Energy Outlook 2021* (AEO2021), (Washington, D.C., February 2021).

ability to provide flexible capacity, the system attributes analyzed include the ability to provide dispatchable peaking capacity, non-dispatchable (i.e., coincidental) peaking 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 (fixed) (LCOC) and LCOE. These metrics are discussed later in this section. Resources are evaluated from a TRC perspective. Idaho Power recognizes the TRC is not in all cases the realized cost to the company. Examples for which the TRC is not the realized cost include 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 views the evaluation of resource options using the TRC as allowing a like-versus-like comparison between resources, and consequently is in the best interest of our 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. The initial capital investment and associated capital costs of resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, plant construction costs, 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. Net levelized costing for the bundled energy efficiency resource options modeled in the IRP are provided in Chapter 5. The net levelized costs for energy efficiency resource options include annual program administrative and marketing costs, an annual incentive, and annual participant costs.

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 in nominal dollars 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 initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, 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 (e.g., wind) having peaking capacity significantly less than installed capacity. The LCOC values for the potential IRP resources are provided in Figure 8.5.

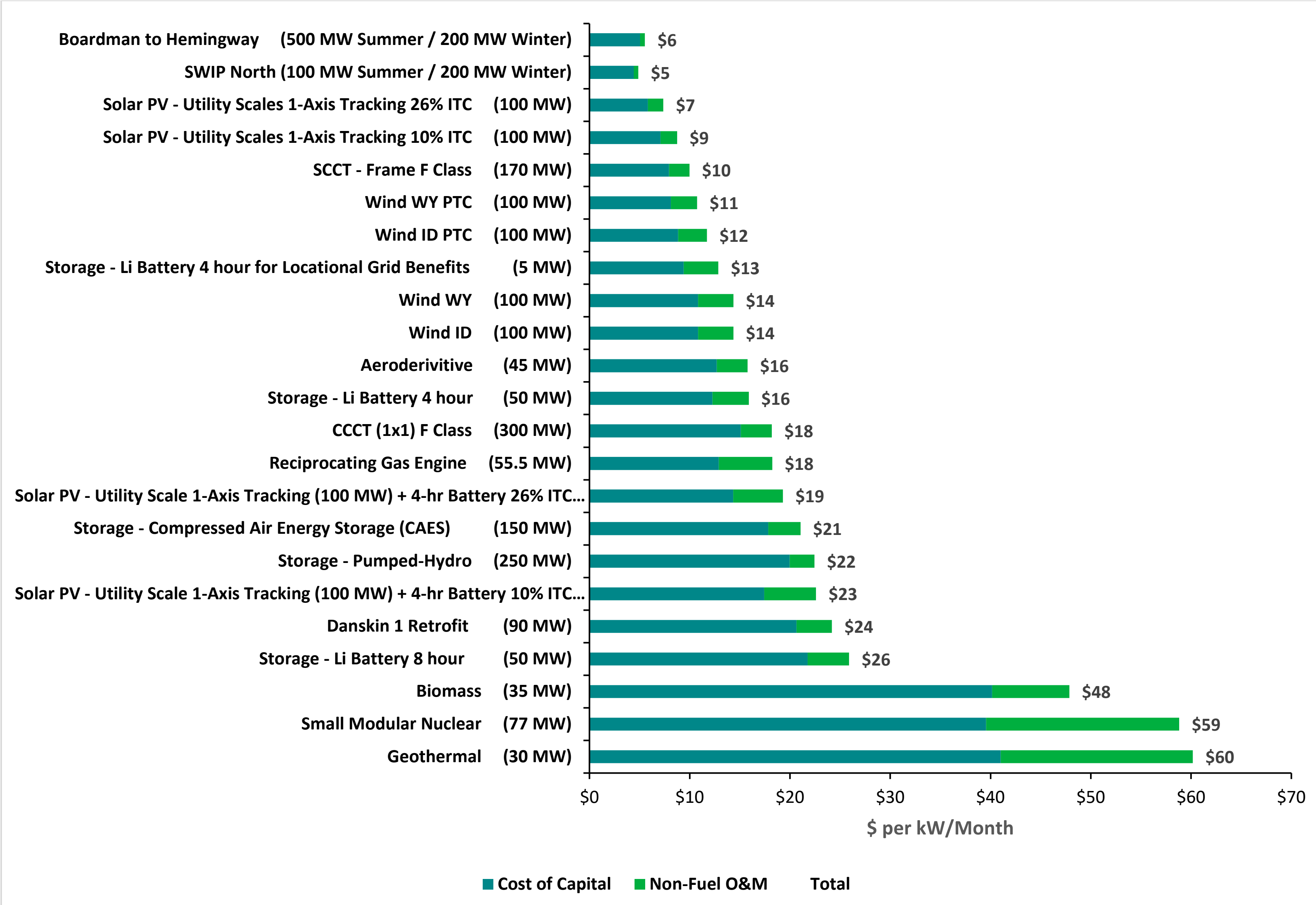


Figure 8.5 Levelized capacity (fixed) costs in millions of 2021 dollars per kW per month[29]

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 in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource. The nominal LCOE assuming the expected capacity factors for each resource is shown in Figure 8.6. Included in these costs are the capital cost, non-fuel O&M, and fuel costs. The cost of recharge energy for storage resources and wholesale energy for B2H are not included in the graphed LCOE values.

The LCOE is provided assuming a common online date of 2021 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 Investment Tax Credit on solar-based energy resources, including coupled solar-battery systems. 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.

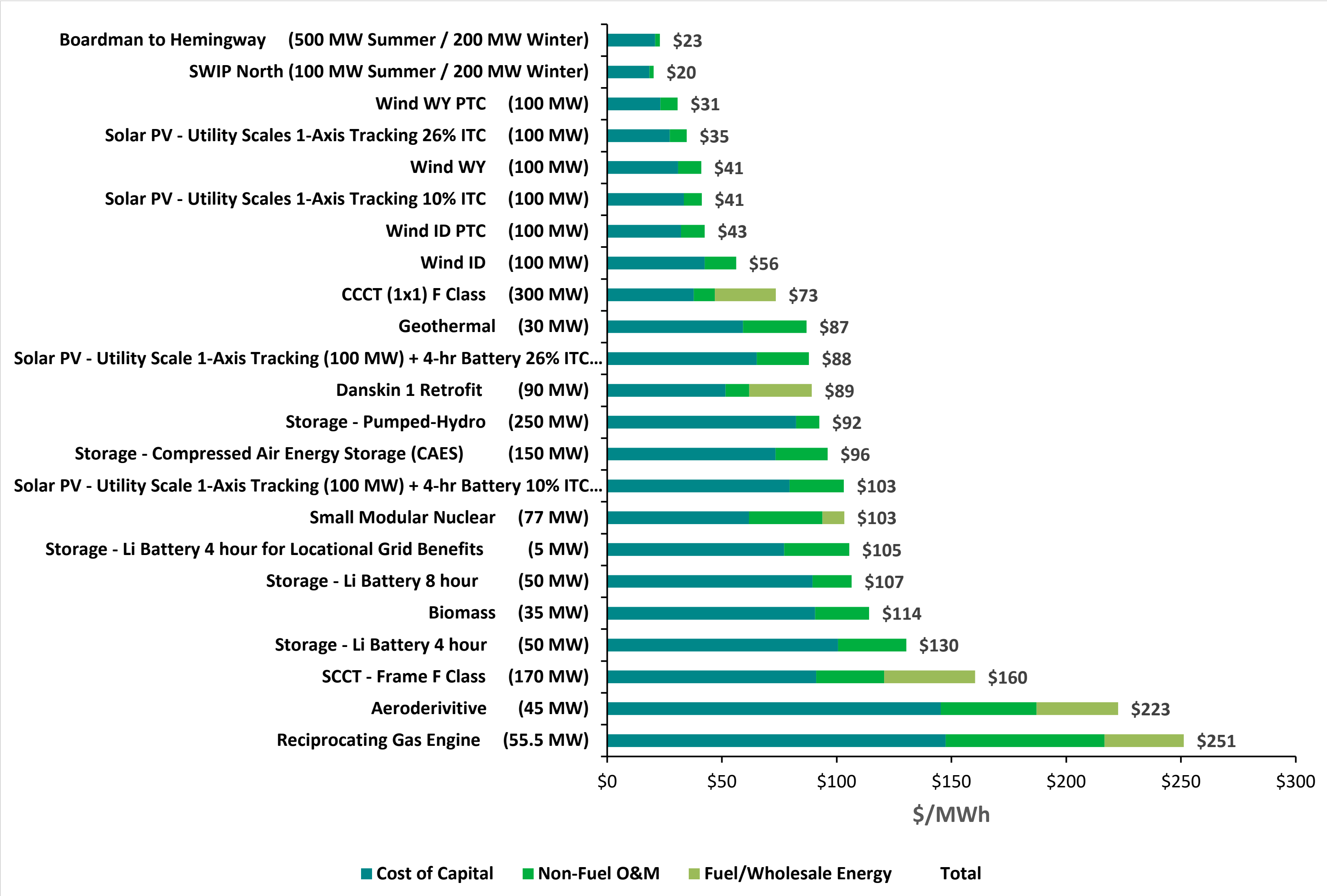


Figure 8.6 Levelized cost of energy (at stated capacity factors) in 2021 dollars

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. For the LCOC metric, this critical distinction 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 $12 per month per kW of installed capacity.[30] However, assuming wind delivers an ELCC equal to 11.2% of installed capacity, the LCOC ($12/month/kW) converts to $107 per month per kW of peaking capacity.

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

In recognition of differences between resource attributes, potential IRP resources for the 2021 IRP are classified based on their attributes.

[30] The units of the denominator can be expressed in reverse order from the cost estimates provided in Figure 8.5 without mathematically changing the cost estimate.

Table 8.4 Resource attributes

Resource	Variable Energy	Dispatchable Capacity-Providing	Non-Dispatchable (Coincidental) Capacity-Providing[31]	Balancing/ Flexibility-Providing	Energy-Providing	Size Potential
Aeroderivitive		✓		✓	✓	45 MW increments
Biomass—Anaerobic Digester		✓			✓	Scalable up to about 35 MW
Boardman to Hemingway 500 kV Project		✓		✓	✓	(500 MW April–Sept., 200 MW Oct.–March)
Compressed Air Energy Storage		✓		✓		150 MW increments
Danskin 1 Retrofit		✓		✓	✓	90 MW
Demand Response		✓				Scalable from 300 MW (default) up to 580 MW in 20 MW increments
Energy Efficiency (Additional Bundles)			✓		✓	Scalable up to achievable potential
Geothermal		✓			✓	Scalable up to about 30 MW
CCCT (1x1)		✓		✓	✓	300 MW increments
SCCT—Frame F Class		✓		✓		170 MW increments
Reciprocating Gas Engine		✓		✓	✓	55.5 MW increments
Small Modular Nuclear		✓		✓	✓	77 MW increments
Solar PV—Utility-Scale 1-Axis Tracking	✓		✓		✓	Scalable
Solar PV—AC Coupled with Lithium Battery	✓	✓			✓	Scalable
Storage—Pumped Hydro		✓		✓		250 MW increments
Storage—Lithium Battery		✓		✓		Scalable
SWIP-North 500 kV Project		✓		✓	✓	(100 MW Summer, 200 MW Winter)
Wind (Wyoming/Idaho)	✓				✓	Scalable

[31] The peaking capacity impact in MW for resources providing coincidental peaking capacity is expected to be less than installed capacity in MW. For solar resources, the coincidental peaking capacity impact diminishes with increased installed solar capacity on system, as described in Chapter 4.

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
- *Non-dispatchable (coincidental) capacity-providing*—Resources whose output tends to naturally occur with moderate likelihood during periods of peak-hour loading or during generally high-value periods
- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from VERs
- *Energy-providing*—Resources producing or reducing the need for energy that are relatively predictable when averaged over long time periods (i.e., monthly or longer)

Table 8.4 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.

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IRP REPORT:
PORTFOLIOS

9. PORTFOLIOS

Prior to modeling for the 2021 IRP, 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 review was a preliminary step prior to modeling for the 2021 IRP. As a result, the sections below describe work that began where the review process concluded. For further detail on the IRP review process, refer to the *2019 IRP Review Report*.

Capacity Expansion Modeling

For the 2021 IRP, 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 based on the performance of 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.

The selection of new resources in the optimized portfolios maintains sufficient reserves as defined in the model. To ensure the AURORA-produced optimized portfolios provide the least-cost, least-risk future specific to the company's customers, the 2021 IRP process used a branching process to find the Preferred Portfolio. This branching process is discussed further in the following sections.

The portfolios developed in the 2021 IRP selected from a broad range of resource types, as well as varied amounts of nameplate generation additions:

- Wind (between 0 and 2,300 MW in total)
    - Wyoming (between 0 and 800 MW)
    - Idaho (between 0 and 1,500 MW)
- Solar (between 785 and 5,285 MW in total)
    - Standalone (between 785 and 2,285 MW)
    - With Battery Storage (between 0 and 3,000 MW)
- Standalone Storage (between 0 and 2,700 MW in total)
    - Pumped Hydro (between 0 and 500 MW)
    - Compressed Air Energy Storage (between 0 and 600 MW)
    - Battery Energy Storage

        - 4 Hour Transmission Connected (between 0 and 1,000 MW)
        - 4 Hour Distribution Connected (between 0 and 100 MW)
        - 8 Hour Transmission Connected (between 0 and 500 MW)
- Natural Gas (between 0 and 2,500 MW in total)
    - Reciprocating Engines (between 0 and 333 MW)
    - CCCT (between 0 and 600 MW)
    - SCCT (between 0 and 850 MW)
        - Aeroderivative (between 0 and 270 MW)
        - Danskin Unit 1 retrofit (0 or 90 MW)
    - Coal to Natural Gas Conversion of Jim Bridger units 1 and 2 (between 0 and 357 MW)
- Nuclear Small Modular Reactor (between 0 and 924 MW)
- Biomass (between 0 and 350 MW)
- Geothermal (between 0 and 300 MW)
- Demand Response (between 0 and additional 280 MW)
- Accelerated Coal Exits (up to 841 MW in total)
    - Jim Bridger (up to 707 MW)
    - North Valmy Unit 2 (134 MW)

Planning Margin

The 2021 IRP used the LTCE capability of the AURORA model to develop a multitude of least-cost portfolio buildouts based on standards, policies, and resources needed to assure reliability. Specifically, to assure reliability, Idaho Power utilized a 50th percentile hourly load forecast and required the AURORA model's LTCE functionality to meet a 15.5% peak-hour planning margin for each of the portfolios that were developed.

The 15.5% target planning margin was calculated based on the 1 day in 20 years (1-in-20), or 0.05 days per year, reliability hurdle as measured by the LOLE. The year 2023 was used as the benchmark year to obtain the planning margin value. The 1-in-20 reliability threshold was chosen to 1) account for the extreme weather events that are becoming more frequent in the Northwest, and 2) factor in water availability uncertainty year to year. A poor water year, resulting in reduced hydro generation, can look equivalent to a season-long resource outage.

This 0.05 days per year threshold is consistent with the metric used by the Northwest Power Conservation Council.

Idaho Power developed an internal LOLE tool which was used to determine the amount of perfect capacity needed, in addition to the company's existing resources, to achieve a target LOLE of 0.05 days per year. The planning margin was then calculated by dividing the total capacity requirements derived in the tool for 2023 by the forecasted peak load for 2023. The summary of the resources and their corresponding summer capacities (in MW) is shown in Table 9.1 below.

Table 9.1 Planning margin calculation breakdown

Resource Type	Summer Capacity (MW)*
Coal	785
Gas	670
Hydro	1,355
Variable Energy Resources	346
Demand Response	176
CSPP (Non-Variable)	163
Capacity Benefit Margin	330
Perfect Resource Requirement from LOLE Tool	463
Total Generation	**4,288**
Forecast Peak Load	**3,712**
Planning Margin	**15.5%**

*The values in this column are adjusted for Effective Forced Outage Rate (EFOR) or ELCC.

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

Portfolio Design Overview

The AURORA LTCE process develops resource portfolios under varying future conditions, or sensitivities for natural gas prices, carbon costs, load growth and electrification, transmission, and clean energy constraints and timelines. The LTCE applies a planning margin 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 should enable Idaho Power to supply cost-effective electricity to customers over the 20-year planning period.

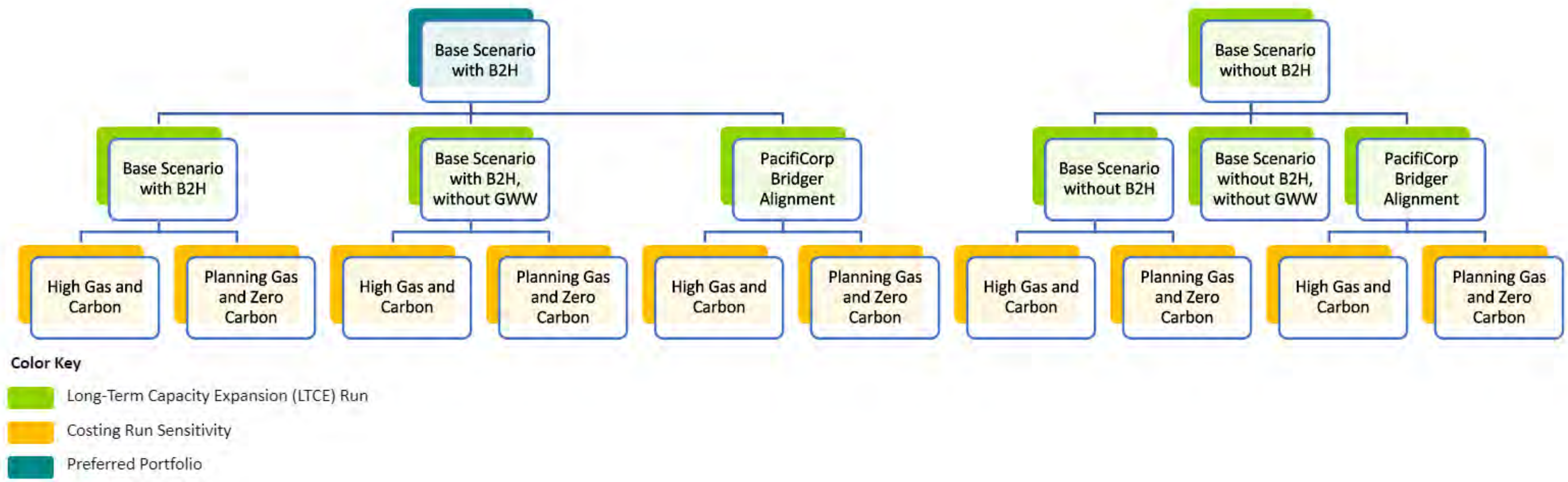

Figure 9.1 Branching analysis diagram

For the 2021 IRP, the company developed a branching scenario analysis strategy to ensure that it had reasonably identified an optimal solution specific to its customers. Figure 9.1 details the initial branching evaluation where the company compared AURORA-optimized portfolios for a base scenario (i.e., planning conditions for all key inputs such as load growth, natural gas price, carbon price, etc.) for six potential future portfolios. Each of these portfolios was fully optimized by the AURORA LTCE model.

1. Base with B2H
2. Base with B2H without Gateway West (ultimately not required)
3. Base with B2H PAC Bridger Alignment
4. Base without B2H
5. Base without B2H without Gateway West
6. Base without B2H PAC Bridger Alignment

The company then compared the base portfolios that included B2H to determine an optimal B2H-included portfolio and compared the base portfolios that did not include B2H to determine an optimal B2H-excluded portfolio. Cost information associated with each portfolio is detailed in Chapter 10.

In the Base with B2H portfolio, the AURORA LTCE model did not identify enough resources to trigger the need for Gateway West; therefore, a Base with B2H without Gateway West portfolio was not required. For the B2H-excluded portfolios, the Gateway West project was required.

The company also developed costs for each of the portfolios assuming a future with: 1) no price on carbon, i.e., zero carbon, and 2) a high price on both carbon and gas. For the Base without B2H without Gateway West portfolio, the company did not continue further evaluation beyond planning conditions due to the portfolio's inferior performance (high-cost, poor reliability, and poor emissions performance).

Comparing the NPV cost of the best B2H-included portfolio—the Base with B2H portfolio—to the best B2H-excluded portfolio—the Base without B2H PAC Bridger Alignment portfolio—there is a $270 million difference. This cost difference definitively shows that the B2H project is a necessary component of the company's Preferred Portfolio (assuming comparable risk performance to other portfolios, which will be explored later in this document) and additional robustness testing, including various sensitivities and scenarios, should be focused on portfolios that include B2H.

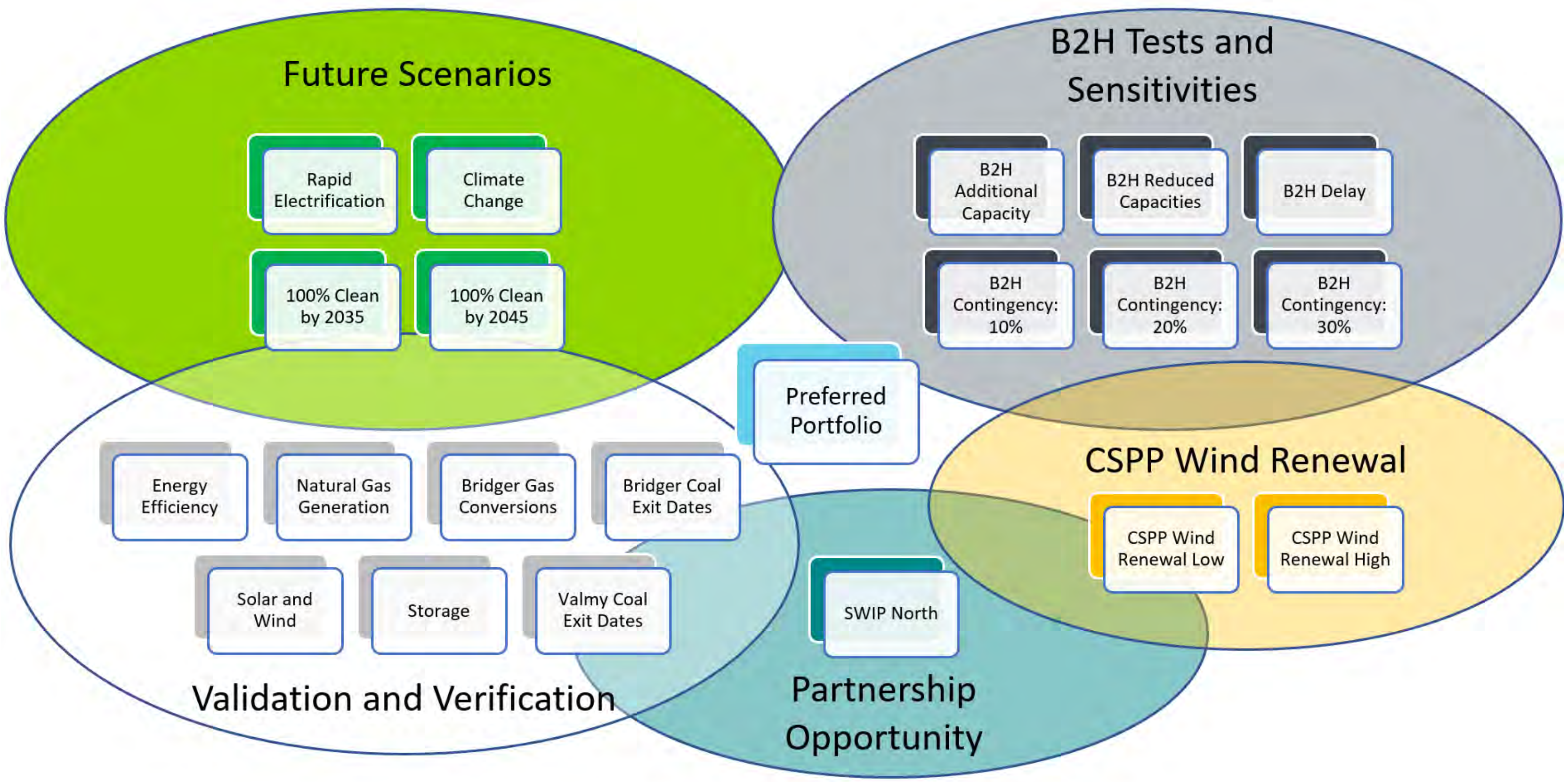

Figure 9.2 Sensitivity analysis diagram

Further branching from the Base with B2H portfolio, the company developed numerous additional portfolios:

- Working with members of the IRPAC, the company developed four future scenarios, in green boxes in Figure 9.2, and described later in this section
- Two sensitivity studies based on varying CSPP Wind Renewal rates, in orange boxes in Figure 9.2, and described later in this section
- One potential regional partnership opportunity, the SWIP-North, in teal boxes in Figure 9.2, and described later in this section
- Several validation and verification tests, in gray boxes in Figure 9.2, and described later in this section
- Various B2H robustness sensitivities and cost tests, in black boxes in Figure 9.2, and described later in this section

Future Scenarios—Purpose: Risk Evaluation

The future scenarios are represented by green boxes in Figure 9.2. These scenarios were developed in collaboration with the IRPAC, including the addition of one scenario, and data sharing. The evaluation and formation of scenarios helps the company assess risk.

The following is a description of the four future scenarios assessed in the 2021 IRP.

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 each by a factor of 10. This aggressive forecast assumes over a half-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 and/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.

Climate Change

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

100% Clean by 2035 Scenario

In the 100% Clean by 2035 scenario, the carbon price adder forecast was removed with an assumption that there was a legislative mandate to move toward 100% clean energy by the year 2035. The AURORA model struggled to obtain a robust solution to achieve zero emissions, WECC-wide, by 2035. To achieve a solution for a 100% clean Idaho Power system by 2035, the company modeled Idaho Power gas unit retirements starting in early 2030, through 2035. The company replaced the retired gas with a non-emitting nuclear resource.

The struggles of the model to achieve a 100% Clean by 2035 scenario are indicative of the challenges faced by the industry to meet a 100% target given technologies commercially available today. 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 Scenario

The 100% Clean by 2045 scenario removes carbon price adder forecasts and assumes a legislative mandate to move towards 100% clean energy by the year 2045 throughout the WECC. The scenario modeling is achieved by applying carbon emission constraints starting in 2021 with current emission levels and decreasing linearly to achieve 0% by the target year. The same constraints were applied to Idaho Power's service area and the surrounding WECC.

Non-emitting resources were used to replace carbon-emitting resources.

CSPP Wind Renewal Sensitivity Studies—Purpose: Portfolio Sensitivity to the Percentage of CSPP Renewal

The CSPP Wind Renewal Sensitivity Studies are represented by orange boxes in Figure 9.2. For the 2021 IRP analysis, based on ongoing discussions with wind developers and the desire to adequately plan for the future, it is assumed that 25% of CSPP wind developers will continue to produce wind energy through 2040. This 25% renewal rate is a departure from the 2019 IRP, in which no wind contracts were assumed to renew. While Idaho Power's developer discussions have not indicated intentions to renew existing contracts, the company and IRP stakeholders, as well as the IPUC and OPUC, agreed that there is value to understanding the portfolio impact of different wind renewal assumptions. In the resulting wind sensitivity analysis, the *CSPP Wind Renewal Low* and *CSPP Wind Renewal High* sensitivities test the 25% renewal assumption by replacing it with 0% and 100% renewal rates, respectively.

Opportunity Evaluation—Purpose: Evaluate Whether to Further Explore SWIP-North

The SWIP-North Opportunity Study is represented by a teal box in Figure 9.2. The SWIP-North opportunity evaluation tests whether Idaho Power customers could benefit from Idaho Power's involvement in the project assuming a pre-summer 2025 project in-service date.

The SWIP-North scenario is described in more detail in Chapter 6—Transmission Planning. The sensitivity test assumes the transmission line could add 100 MW of import capacity during the summer and 200 MW of import capacity during the winter for Idaho Power. The 100 MW in the summer and 200 MW in the winter would count toward meetings the company's planning margin requirements, i.e., the line is being treated as a 100 MW summer resource and a 200 MW winter resource.

Model Validation and Verification—Purpose: Model Validation and Verification

The Model Validation and Verification tests are represented by gray boxes in Figure 9.2. The Model Validation and Verification tests on the diagram represent several sensitivities and test studies performed to ensure the model is operating as expected and to verify that the selected Preferred Portfolio represents a robust optimization of cost and risk, with a specific focus on validation and verification within the Action Plan window. The following list includes significant examples but is not all-inclusive of the testing that was performed on the model.

Demand Response

Background—Concurrent with the 2021 IRP analysis, the parameters of current DR programs are being reevaluated to align the programs with the highest risk hours on Idaho Power's system, as described in Chapter 6. In addition to the refinement of the current program, additional DR was selected as a cost-effective means to meet growing energy demand.

Test—To ensure the appropriate amount of DR is being selected by the model, the model was tested with more DR in earlier years to determine if the addition would result in a lower-cost portfolio.

Result—Additional DR placed earlier in the plan results in increased portfolio costs, as expected.

Energy Efficiency

Background—Cost-effective energy efficiency measures, as determined in the Potential Assessment, are included as part of the IRP. Additional measures were grouped into buckets and selectable within the model to meet increasing demand and fill the gap when generation resources are exited. Some of these buckets were selected as part of the Preferred Portfolio late in the plan (3 MW in 2039 and 9 MW in 2040).

Test—The lowest-cost bundles of energy efficiency selectable within the model were added early in the plan timeframe.

Result—The earlier implementation of the energy efficiency measures beyond those determined to be cost-effective in the Potential Assessment did not result in a lower-cost portfolio.

Natural Gas Generation and Solar Plus Storage

Background—Wind, solar, and storage were primarily selected in the Preferred Portfolio and other portfolios. Natural gas generation was not.

Test—A natural gas generator was placed in the model in year 2028 to replace the capacity previously provided by the Bridger units instead of the solar and storage selected by the model.

Result—Replacing solar and storage with natural gas does not result in reduced resource costs.

Bridger Natural Gas Conversion (Units 1 and 2)

Background—Given a relatively low cost to convert Bridger units 1 and 2 to natural gas operation, the conversion was consistently selected as economical by the model with a 2034 depreciable life exit date.

Test—Various modeling tests were performed to determine if it is more economical to either exit Bridger units 1 and 2 or delay the natural gas conversion of Unit 2.

Result—Exiting the units rather than converting to natural gas operation increased the cost of the portfolio. Delaying the conversion also resulted in additional costs.

Bridger Coal Exit Dates (Units 3 and 4)

Background—Bridger units 3 and 4 have identified exits in 2025 and 2028 in the Preferred Portfolio. That is earlier than the exits identified in the 2019 IRP (2028 and 2030, respectively).

Test—These dates were adjusted earlier (2025 and 2027) and later (2028 and 2030) and the portfolio was tested to determine if shifting the coal exit dates resulted in a reduced cost portfolio.

Result—Shifting the exit dates for Bridger units 3 and 4 does not result in a lower portfolio cost.

Geothermal and Biomass

Background—Geothermal and biomass resources were not selected in portfolio and scenario studies.

Test—Geothermal and biomass were each added to the Preferred Portfolio in the place of a selected flexible resource. The portfolio was then costed to determine if resource costs would decrease.

Result—The shift to geothermal or biomass generation increased overall portfolio costs as expected.

Valmy

Background—Idaho Power is scheduled to exit Valmy Unit 2 by the end of 2025.

Test—Sensitivities were studied to determine if it is more economical to exit the unit earlier (year-end 2023 or 2024).

Result—An earlier exit from Valmy Unit 2 increases portfolio costs.

B2H Robustness—Purpose: Test Capacity Sensitivities, Cost Risks, and Timing

The B2H robustness and sensitivity studies are represented by the black boxes in Figure 9.2. The B2H project is a key component of the company's 2021 IRP. The company models B2H as providing 500 MW of peak capacity toward meeting the company's planning margin requirements. The capacity sensitivity tests looked at B2H providing various amounts of planning margin capacity: 1) 350 MW, 2) 400 MW, 3) 450 MW, and 4) 550 MW.

As an approximately 300-mile high-voltage transmission line, the cost of the project also requires evaluation for risk. The cost-sensitivity tests looked at the cost of B2H with: 1) a 10% contingency; 2) a 20% contingency; and 3) a 30% contingency.

Idaho Power anticipates it will receive a B2H permit in 2022, however, additional delays are possible. To test the impact of a delay, the company evaluated a 2027 in-service date as a sensitivity.

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, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2021 IRP include defining hourly reserve requirements for "Load Up," "Load Down," "Solar Up," "Solar Down," "Wind Up," and "Wind Down."

For the 2021 IRP analysis, Idaho Power developed approximations for the VER study's regulating reserve rules. These approximations are necessary because a 20-year period is simulated for the IRP (as opposed to the single year of a VER study), and to allow the evaluation of portfolios containing varying amounts of VER generating capacity (i.e., the VER-caused regulating reserve requirements are calculable). The approximations express the up and down regulation reserve requirements as dynamic and monthly percentages of hourly load, wind production, and solar production. The approximations used for the IRP are given in Table 9.2. For each hour of the AURORA simulations, the dynamically determined regulating reserve is the sum of that calculated for each individual element.

Table 9.2 Regulation reserve requirements—percentage of hourly load MW, wind MW, and solar MW

Month	Load Up	Load Down	Wind Up	Wind Down	Solar Up	Solar Down
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%

It is emphasized that the regulating reserve levels used in the 2021 IRP are approximations intended to reflect generally the amount of set-aside capacity needed to balance load and wind and solar production while maintaining system reliability. The precise definition of regulating reserve levels is more appropriately the focus of a study designed specifically to assess the impacts and costs associated with integrating VERs.

Natural Gas Price Forecasts

Idaho Power used the long-term Platts 2021 Henry Hub natural gas price forecast as the planning case forecast in the 2021 IRP. Idaho Power tested portfolios under an additional (high) natural gas price forecast, EIA's Low Oil & Gas Supply forecast from their *Annual Energy Outlook 2021.*[32] For more details and discussion on the planning natural gas price forecast, see Chapter 8.

Carbon Price Forecasts

Idaho Power developed portfolios under three carbon price scenarios for the 2021 IRP shown in Figure 9.3:

1. Zero Carbon Costs—assumes there will be no federal or state legislation that would require a tax or fee on carbon emissions.
2. Planning Case Carbon Cost—is based on the California Energy Commission's 2020 *Integrated Energy Policy Report (IEPR) Preliminary Green House Gas Allowance Price*

[32] EIA Annual Energy Outlook 2021, February 2021: www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

Projections[33], Low-price Scenario. The carbon cost forecast assumes a price of roughly $20 per ton beginning in 2023 and increases to nearly $68 per ton by the end of the IRP planning horizon.

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.*[34] The carbon cost forecast assumes a price of approximately $53 per ton beginning in 2021 that increases to more than $105 per ton (nominal dollars) by the end of the IRP planning horizon.

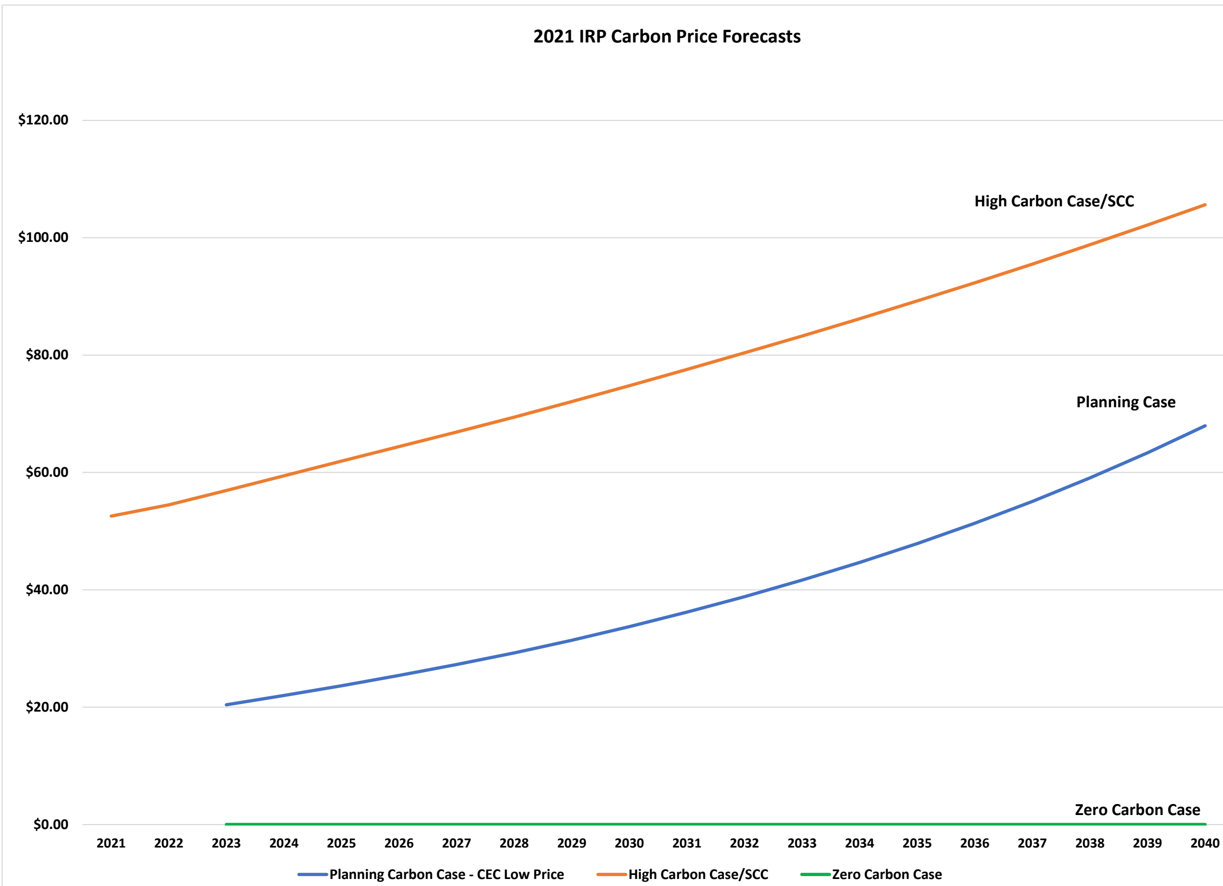

Figure 9.3 Carbon price forecast

[33] 2020 California Energy Commission's *IEPR Preliminary Green House Gas Allowance Price Projections*, Low-price Scenario. Energy Assessment Division (August 13, 2020)

[34] 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 https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

IRP REPORT:

MODELING ANALYSIS

10. MODELING ANALYSIS

Portfolio Cost Analysis and Results

Once the portfolios are created using the LTCE model, Idaho Power uses the AURORA electric market model 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 wholesale market energy pricing and resource operation and emissions data. It should be noted that the Portfolio Cost Analysis is a step that occurs *following* the development of the resource buildouts through the LTCE model; the Portfolio Cost Analysis utilizes the resource buildouts from the LTCE model as an input. The LTCE and Portfolio Cost analyses are performed sequentially.

The AURORA software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast market 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 is 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	2.30%
Annual property tax rate (% of investment)	0.47%
B2H annual property tax rate (% of investment)	0.64%
Property tax escalation rate	3.00%
B2H property tax escalation rate	0.68%
Annual insurance premium (% of investment)	0.049%
B2H annual insurance premium (% of investment)	0.004%
Insurance escalation rate	3.00%
B2H insurance escalation rate	3.00%
AFUDC rate (annual)	7.45%

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

Table 10.2 AURORA hourly simulations

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

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

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

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

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$7,915,702	$7,186,761	$9,832,001
Base B2H PAC Bridger Alignment	$7,999,347	$7,152,955	$9,932,925
Base without B2H	$8,192,830	$7,784,545	$9,474,983
Base without B2H without Gateway West[35]	$8,441,414	-	-
Base without B2H PAC Bridger Alignment	$8,185,334	$7,588,228	$9,652,891
Base with B2H—High Gas High Carbon Test[36]	$7,997,339	-	$9,424,935

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

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

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

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

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

Sensitivity	Cost
Preferred Portfolio (Base with B2H)	$7,915,702
SWIP-North	$7,887,562
CSPP Wind Renewal Low	$7,892,585
CSPP Wind Renewal High	$7,926,005

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

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

Validation & Verification Tests	Cost
Preferred Portfolio (Base with B2H)	$7,915,702
Demand Response	$7,917,643
Energy Efficiency	$8,143,113
Natural Gas in 2028 Rather than Solar and Storage	$8,052,194
Bridger Exit Units 1 & 2 at the End of 2023	$8,073,162
Bridger Exit Unit 2 at the End of 2026	$7,997,648
Bridger Unit 2 Delayed Gas Conversion (2027)	$7,938,805
Bridger Exit Unit 4 in 2027	$7,925,427
Bridger Exit Units 3 and 4 in 2028 and 2030	$7,969,378
Geothermal	$7,973,781
Biomass	$7,968,264
Valmy Unit 2 Exit in 2023	$7,930,664
Valmy Unit 2 Exit in 2024	$7,929,939

Portfolio Emission Results

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

Figure 10.1 is a stacked column that shows the year-to-year cumulative emissions for each portfolio's projected generating resources during those first seven years of the IRP (2021-2027; the Action Plan window).

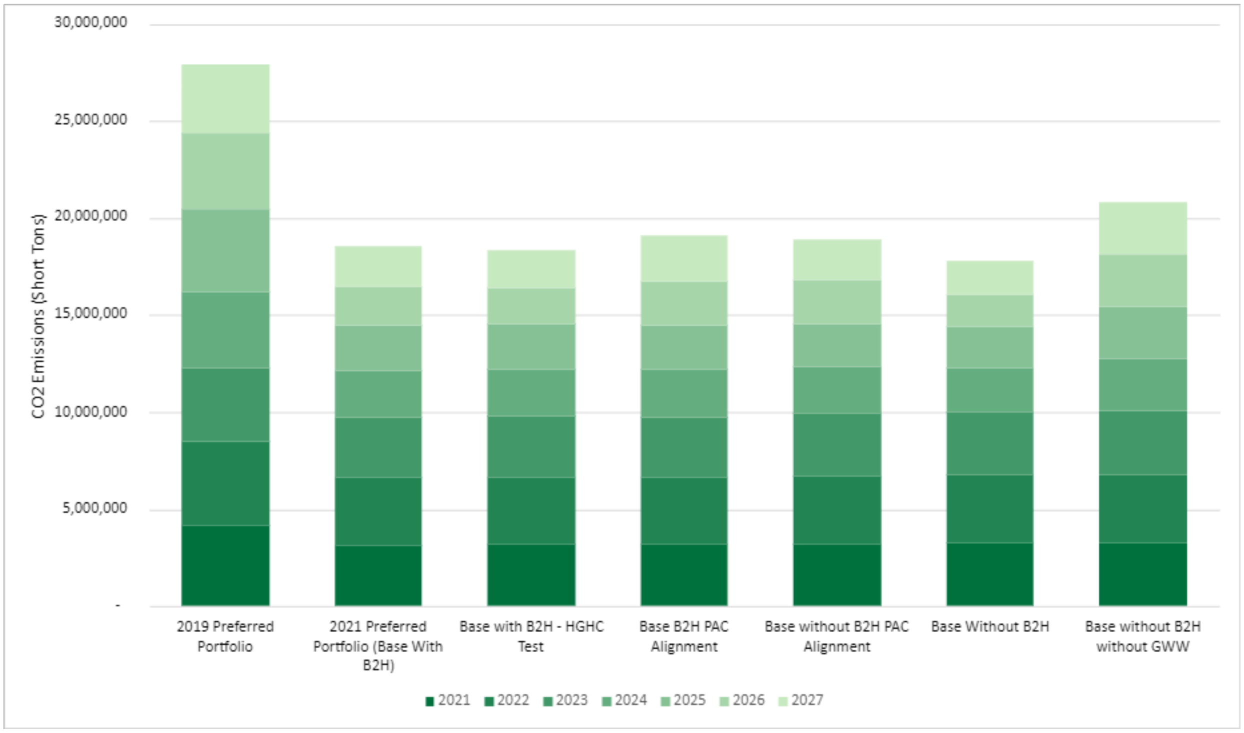

Figure 10.1 Estimated Action Plan window portfolio emissions from 2021–2027

Inspecting the emissions of the Preferred Portfolio in more detail, total emissions reduce from about 3.1 million tons in 2021, to 2 million tons in 2027—representing a 36% reduction over seven years. Additionally, the company is forecasting significant load growth over this seven-year period, so the carbon intensity per MWh is even further reduced. The Preferred Portfolio carbon intensity per MWh reduces from 379 pounds per MWh in 2021, to 209 pounds per MWh in 2027—representing a 45% reduction over seven years. The company believes a 36% reduction in total emissions, and a 45% reduction in emissions intensity, over a seven-year period represents a significant step toward its 100% Clean by 2045 goal.

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

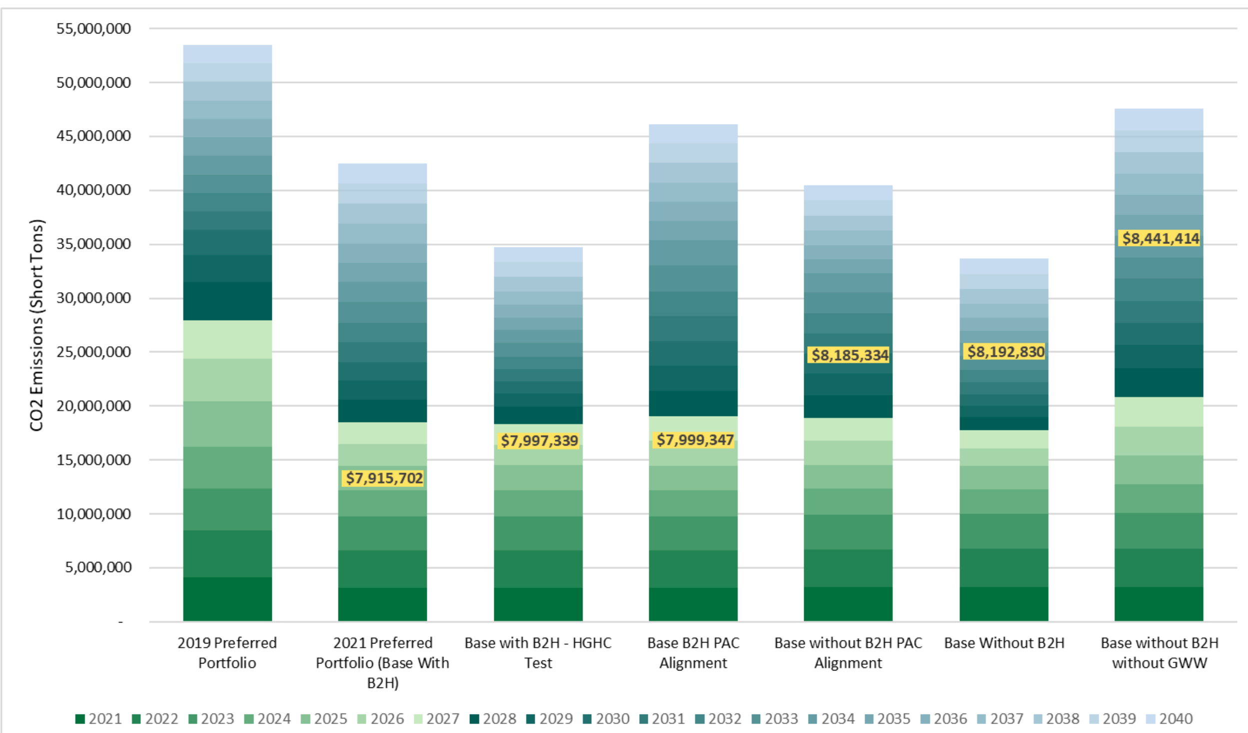

Figure 10.2 Estimated portfolio emissions from 2021–2040

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

Idaho Power believes that technological advances will continue to occur to allow the company to reliably and cost-effectively achieve our goal of providing 100% clean energy by 2045.

Qualitative Risk Analysis

Major Qualitative Risks

Fuel Supply—All generation and transmission resources require fuel to provide electricity. Different resource types have different fuel supply risks. Renewable resources rely on uncertain future weather conditions to provide the fuel be it wind, sun, or water. Weather can be variable and difficult to forecast accurately. 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. 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 the amount of new resources dependent on the capacity constrained infrastructure.

Fuel Price Volatility—For plants needing purchased fuel, the 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 and/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.

Market Access—With many utilities including Idaho Power relying more on intermittent resources like wind and solar, the ability to access markets like the Energy Imbalance Market 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.

Technological Obsolescence—Technological innovation may result in generating resources that are lower cost and have more desirable characteristics. As a result, current technologies may become noncompetitive and strand investments which may adversely impact customers economically.

Partnerships—Idaho Power is a partner in coal 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 the Idaho Power electrical system composition is an important consideration. Examples include carbon emission limits or adders, PURPA rules governing renewable PPAs, tax incentives and subsidies for renewable generation or other environmental or political reasons. New or changed rules could harm customers economically 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 to the power industry and accordingly does not consider exceedingly rare or hypothetical events, like a Sharknado, 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 the following table:

Table 10.6 Qualitative risk comparison

Portfolio	Energy Supply	Market Volatility	Access to Markets	Siting and Permitting	Technological Obsolescence	Partnerships	State and Federal Policy
Base with B2H	Medium	Medium	Low	Medium	Low	Medium	Medium
Base B2H PAC Bridger Alignment	Low	Medium	Medium	Medium	Low	Medium	High
Base Without B2H	Medium	Medium	High	High	Medium	Medium	Medium
Base Without B2H Without GWW	Medium	Medium	High	Medium	High	Low	Medium
Base Without B2H PAC Bridger Alignment	Medium	Medium	High	High	Medium	Medium	High

Operational Considerations

System Regulation—Maintaining a reliable system is a delicate balance requiring generation to match load on a sub-hourly time step. Over- and under-generation due to variability in load and generation require a system to have dispatchable resources available at all times to maintain reliability and to comply with FERC rules and Western EIM flexibility requirements. Outages or other system conditions can impact the availability of dispatchable resources to provide flexibility. For example, in the spring, hydro conditions and flood control requirements can limit the availability of hydro units to ramp up or down in response to changing load and non-dispatchable generation. Not having hydro units available to follow load increases the reliance on baseload thermal resources like the Bridger units as the primary flexible resources to maintain system reliability and comply with FERC and EIM rules. Increasing the variability of generation or reducing the availability of flexible resources can adversely impact the customer economically, Idaho Power's ability to comply with environmental requirements, and the reliability of the system.

Stochastic Risk Analysis

The stochastic risk analysis assesses the effect on portfolio costs when select variables take on 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 risk and the shape of that risk. To assess stochastic risk, the key drivers of natural gas prices, customer load, and hydroelectric generation 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* of the 2021 IRP.

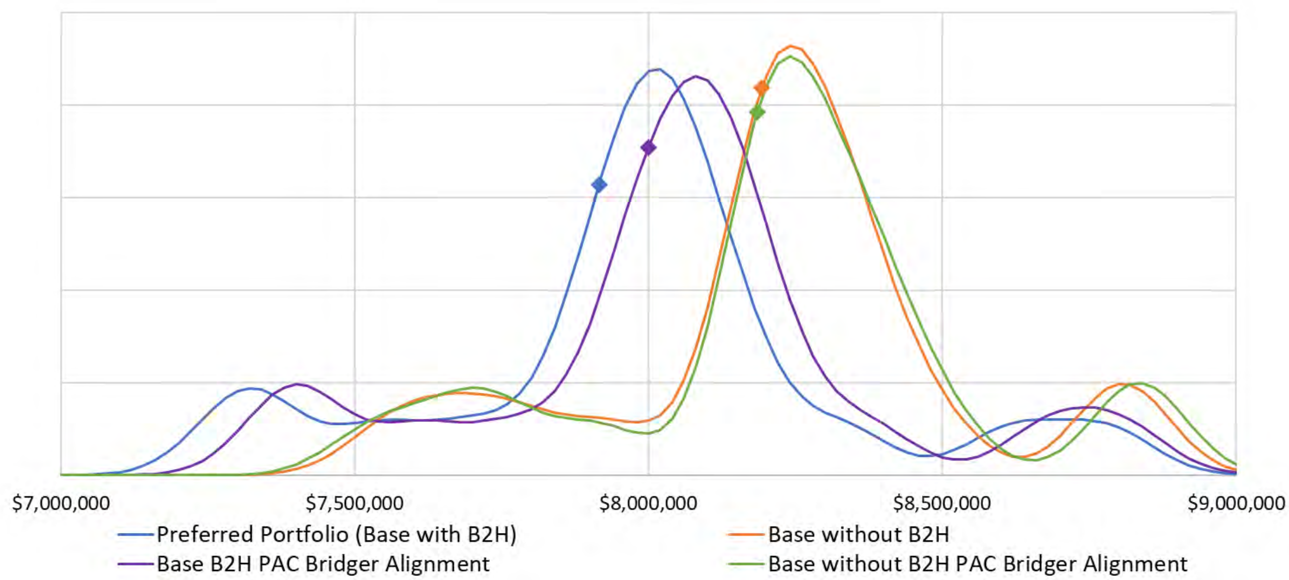

Figure 10.3 NPV stochastic probability kernel (likelihood by NPV [$ x 1,000])

In Figure 10.3, each line represents the likelihood of occurrence by NPV with the diamonds showing the planning conditions 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 (Base with B2H) has the lowest cost given a range of natural gas prices, load forecasts, and hydroelectric generation levels. Next lowest is the Base with B2H PAC Bridger Alignment portfolio indicated by the middle peak. Nearly tied as the most expensive options analyzed using stochastic elements are both Base without B2H portfolios regardless of PAC Bridger Alignment.

Loss of Load Evaluation of Portfolios

As a post-processing reliability evaluation, Idaho Power calculated the LOLE of various AURORA-produced portfolios, on an annual basis, to ensure the selected portfolios achieved the 0.05 LOLE minimum reliability threshold. This was an important evaluation because the company utilized static ELCC values for each resource type modeled, whereas resource ELCCs can vary depending on the total resource makeup of a portfolio. For example, if a portfolio consisted only of large amounts of storage, there would eventually be issues with obtaining enough energy to charge the storage. Diverse resources, such as solar coupled with storage, address that issue as a good resource pairing. Evaluating the LOLE of portfolios on an annual basis is necessary to ensure each selected portfolio meets the reliability threshold.

The portfolio LOLE was obtained by calculating the probability that the generation would not be able to meet the demand at any given hour over the planning horizon. An in-depth discussion of the LOLE methodology and calculations can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*.

Idaho Power used four test years to ensure the selected portfolios were reliable; using a test year ensured the relationship was maintained between variable resources and load. The test years were created using historical data from 2017–2020. The solar output of the selected portfolios was a scaled-up version of the test year's measured PV output. For wind, model data was used instead of measured data because new wind plants will have a significantly different output profile due to the hub height and improvements in wind technology in the last decade. The load profile in each of the test years was created by scaling up each month of test year measured data to match the peak load in that month of the load forecast.

The LOLE of each of the four test years was then averaged to obtain a portfolio LOLE for every year of the planning horizon. In the case where any of the years in a given portfolio were above the threshold, the company determined the generator size required that would be sufficient to allow the portfolio to meet the reliability LOLE threshold of 0.05 days per year.

LOLE Results of Selected Portfolios

The annual LOLE values were calculated for the following portfolios:

- Preferred Portfolio (Base with B2H)
- Base without B2H
- Base with B2H PAC Bridger Alignment
- Base without B2H PAC Bridger Alignment
- SWIP-North

The average LOLE values for the Preferred Portfolio are shown below in Figure 10.4; this figure shows the Preferred Portfolio remaining under the reliability threshold until 2036 (excluding 2021 and 2022 due to the 2021 IRP transition from an LOLE of 1 in 10 days per year to 1 in 20 days per year). In 2037, a generator was added to the LOLE tool to keep the Preferred Portfolio under the reliability threshold.

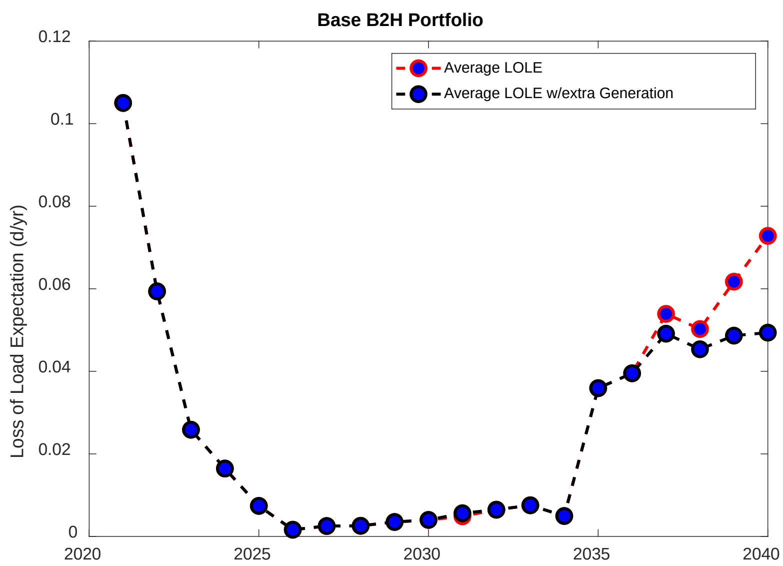

Figure 10.4 Annual loss of load expectation for the Preferred Portfolio

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

Capacity Planning Margin

Idaho Power calculated the capacity planning margin resulting from the resource needs identified in the Preferred Portfolio (Base with B2H). The peak hour capabilities of solar, wind, battery, and DR resources were adjusted based on the calculated ELCCs determined from the LOLE analysis. Resource capacities were also adjusted to account for Effective Forced Outage Rates (EFOR). For hydroelectric generation, expected case (50^{th} percentile) water conditions were used.

The generation from existing resources also includes expected firm purchases from regional markets. Transmission capacity internally set aside with a corresponding reservation on neighboring systems were considered for these expected firm purchases from regional markets. These firm purchases from regional markets are designated as third-party secured transmission. The addition of B2H in 2026 increases transfer capability from the Mid-C market in the northwest. The B2H project will also come with a new corresponding transmission service reservation from the Mid-C market hub to the Longhorn terminal of B2H. Therefore, the new B2H transmission capacity is also considered third-party secured. Transmission import capacity held for emergency use (capacity benefit margin [CBM]) is also included in the capacity planning margin.

The resource total is then compared with the expected-case (50th percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides another view of the adequacy of the Preferred Portfolio. A load and resource balance table with a calculated planning margin is shown in Table 10.7 for the peak load months of July. The target 15.5% planning reserve margin is closely followed by the Preferred Portfolio. A full load and resource balance table showing all months in the 20-year planning period is included in the *Appendix C—Technical Report* of the 2021 IRP.

Table 10.7 July peak hour load and resource balance

	Jul-21	Jul-22	Jul-23	Jul-24	Jul-25	Jul-26	Jul-27	Jul-28	Jul-29	Jul-30	Jul-31	Jul-32	Jul-33	Jul-34	Jul-35	Jul-36	Jul-37	Jul-38	Jul-39	Jul-40
Peak-Hour (50th+15.5%) w/Energy Efficiency	(4,161)	(4,226)	(4,301)	(4,385)	(4,508)	(4,620)	(4,724)	(4,816)	(4,859)	(4,904)	(4,944)	(4,989)	(5,029)	(5,080)	(5,133)	(5,187)	(5,244)	(5,304)	(5,361)	(5,421)
Existing Demand Response Capacity	66	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
Peak-Hour (50th+15.5%) w/DR and Energy Efficiency	**(4,096)**	(4,050)	(4,126)	(4,210)	(4,332)	(4,445)	(4,548)	(4,640)	(4,684)	(4,729)	(4,769)	(4,813)	(4,854)	(4,905)	(4,957)	(5,011)	(5,069)	(5,129)	(5,185)	(5,246)
Existing Resources																				
Bridger	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Coal	**784**	**784**	**784**	**784**	**784**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	270	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306
Total Gas Peakers	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365
Total Gas	**636**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**	**671**
Hydro (50th) HCC	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
Hydro (50th) Other	295	295	295	295	295	294	294	294	294	294	294	293	293	293	293	292	292	292	292	292
Total Hydroelectric (50)	**1,355**	**1,355**	**1,355**	**1,355**	**1,355**	**1,355**	**1,355**	**1,354**	**1,354**	**1,354**	**1,354**	**1,354**	**1,354**	**1,353**	**1,353**	**1,353**	**1,353**	**1,352**	**1,352**	**1,352**
CSPP (PURPA)																				
Solar CSPP (PURPA)	197	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199
Wind CSPP Capacity	93	93	93	93	93	91	91	91	85	81	60	57	38	38	38	38	23	23	23	23
Other CSPP	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Total CSPP	**420**	**422**	**422**	**422**	**422**	**420**	**420**	**420**	**414**	**410**	**389**	**387**	**367**	**367**	**367**	**367**	**352**	**352**	**352**	**352**
Elkhorn	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-	-	-	-
Raft River Geothermal	8	8	8	8	8	8	8	8	8	8	8	8	-	-	-	-	-	-	-	-
Neal Hot Springs Geothermal	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	-	-	-
Jackpot Solar	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Clatskanie Exchange	11	11	11	11	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total PPAs	**42**	**42**	**82**	**82**	**82**	**71**	**71**	**56**	**56**	**56**	**56**	**56**	**48**	**48**	**48**	**48**	**48**	**40**	**40**	**40**
Available Transmission w/Third- Party Secured	**200**	**300**	**380**	**379**	**377**	**375**	**374**	**373**	**372**	**371**	**370**	**370**	**370**	**370**	**370**	**370**	**370**	**370**	**370**	**370**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,767**	**3,904**	**4,025**	**4,023**	**4,021**	**3,885**	**3,883**	**3,867**	**3,861**	**3,856**	**3,833**	**3,830**	**3,803**	**3,802**	**3,802**	**3,802**	**3,787**	**3,780**	**3,780**	**3,780**
Monthly Surplus/ Deficit	**(329)**	(146)	(101)	(186)	(311)	(560)	(665)	(773)	(823)	(873)	(935)	(983)	(1,051)	(1,102)	(1,155)	(1,210)	(1,282)	(1,349)	(1,406)	(1,466)
2021 IRP Capacity Resources																				

	Jul-21	Jul-22	Jul-23	Jul-24	Jul-25	Jul-26	Jul-27	Jul-28	Jul-29	Jul-30	Jul-31	Jul-32	Jul-33	Jul-34	Jul-35	Jul-36	Jul-37	Jul-38	Jul-39	Jul-40
New Transmission–B2H	-	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
New Resource–EE Bundles	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	5
New Resource–DR	-	-	7	7	14	14	14	14	14	14	14	14	14	14	14	14	14	22	29	36
New Resource–Battery–4Hr	-	-	101	105	109	109	114	162	298	346	394	442	529	573	753	757	849	853	901	949
New Resource–Battery–4Hr–Removals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(101)	(105)	(109)
New Resource–Battery–8Hr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	49	97	97	97
New Resource–Solar + Storage 1:1 (Solar)	-	-	-	-	10	10	10	10	20	20	20	20	20	31	41	41	41	51	51	51
New Resource–Solar + Storage 1:1 (Storage)	-	-	-	-	87	87	87	87	174	174	174	174	174	260	347	347	347	434	434	434
New Resource–Solar	-	-	-	-	20	42	68	80	80	80	80	80	80	80	80	80	80	80	80	80
New Resource–WY Wind	-	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
New Resource–ID Wind	-	-	-	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
New Resource–Gas Conversion (Exit 2034)	-	-	-	334	334	334	334	334	334	334	334	334	334	334	-	-	-	-	-	-
Early Bridger Coal Exits	-	-	-	(334)	(334)	(497)	(497)	(497)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	**0**	**0**	**108**	**190**	**319**	**678**	**708**	**768**	**835**	**883**	**932**	**980**	**1,067**	**1,208**	**1,150**	**1,203**	**1,295**	**1,351**	**1,404**	**1,458**
Monthly Surplus/Deficit	**(329)**	**(146)**	**7**	**4**	**8**	**118**	**44**	**(4)**	**12**	**10**	**(4)**	**(3)**	**16**	**106**	**(5)**	**(7)**	**13**	**2**	**(2)**	**(8)**
Planning Margin	**6.4%**	**11.5%**	**15.7%**	**15.6%**	**15.7%**	**18.5%**	**16.6%**	**15.4%**	**15.8%**	**15.7%**	**15.4%**	**15.4%**	**15.9%**	**17.9%**	**15.4%**	**15.3%**	**15.8%**	**15.5%**	**15.5%**	**15.3%**

SWIP-North Opportunity Evaluation

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

- Preferred Portfolio (Base with B2H) NPV—$7,915,702
- SWIP-North Portfolio NPV—$7,887,562

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

B2H Robustness Testing

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

B2H Capacity Evaluation

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

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

Table 10.8 B2H capacity sensitivities

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

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

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

B2H Cost Risk Evaluation

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

Table 10.9 B2H cost sensitivities

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

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

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

B2H In-Service Date Risk Evaluation

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

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

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

	Portfolio Costs	Portfolio Cost Compared to B2H 2027 Portfolio
Preferred Portfolio (Base with B2H)	$7,915,702	-$69,062
Base with B2H in 2027	$7,984,764	-
Base without B2H PAC Alignment	$8,185,334	$200,570

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

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

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

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

The most recent BPA adequacy assessment report was released in October 2020 and evaluates resource adequacy from 2021 through 2030.[37] BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled online date. Similarly, retiring resources are removed on the date of the announced retirement. Resource forecasts for the region assume the retirement of the following coal projects over the study period:

Table 10.11 Coal retirement forecast

Resource	Retirement Date
Centralia 1	December 1, 2020
Boardman	January 1, 2021
Valmy 1	January 1, 2022
Colstrip 1	June 30, 2022
Colstrip 2	June 30, 2022
Centralia 2	December 1, 2025
Valmy 2	January 1, 2026

[37] BPA. 2019 Pacific Northwest loads and resources study (2019 white book). Technical Appendix, Volume 2: Capacity Analysis. https://www.bpa.gov/p/Generation/White-Book/wb/2019-WBK-Technical-Appendix-Volume-2-Capacity-Analysis.pdf. Accessed November 24, 2021.

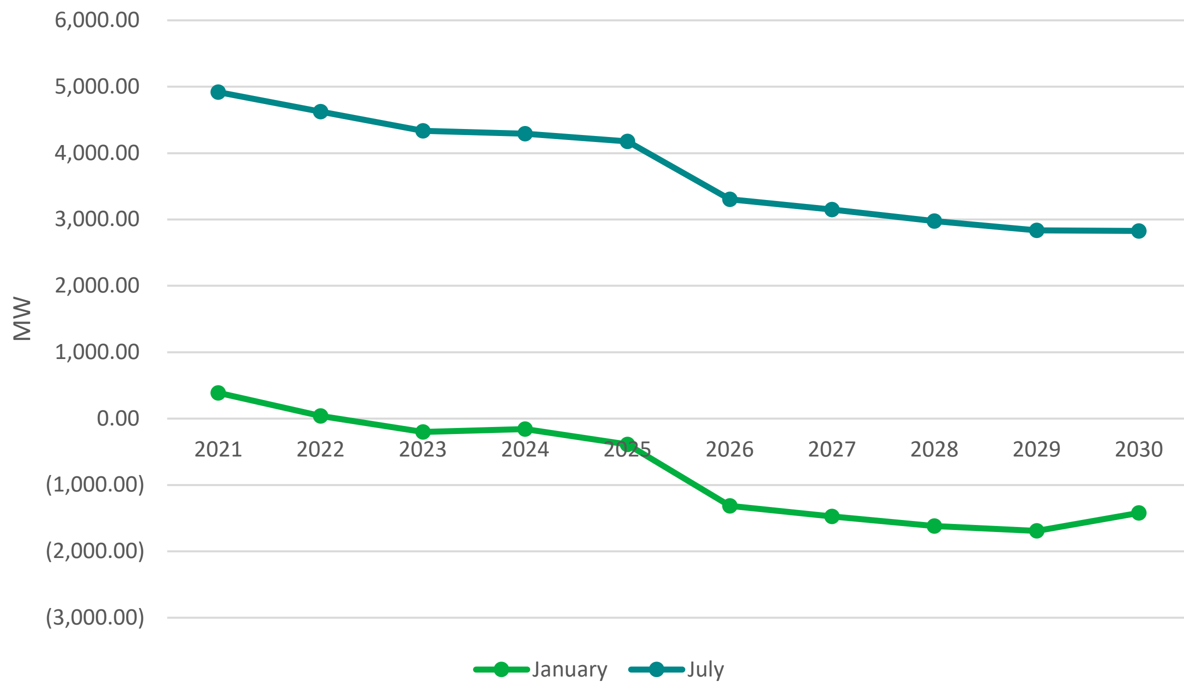

Figure 10.5 BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

For illustrative purposes, Idaho Power downloaded peak load data reported through FERC Form 714 for the major Pacific Northwest entities in Washington and Oregon: Avista, BPA, Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, PGE, Puget Sound Energy, Seattle City Light, and Tacoma (PacifiCorp West data was unavailable). The coincident sum of these entities' total load is shown in Figure 10.6.

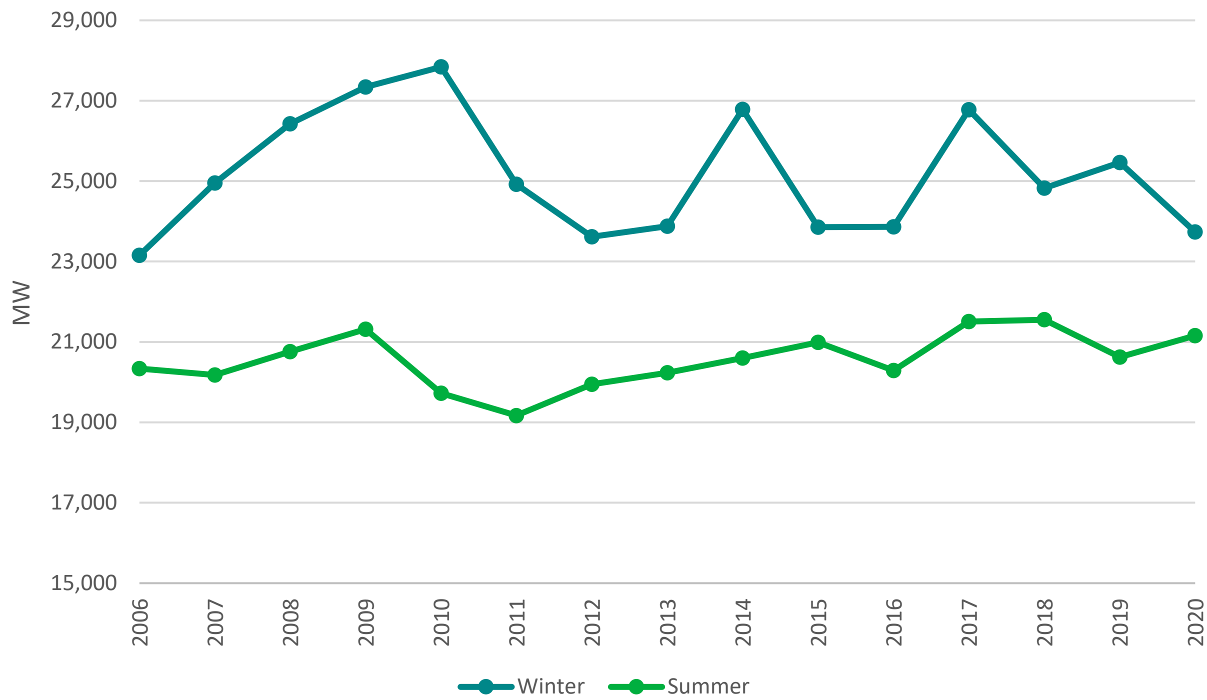

Figure 10.6 Peak coincident load data for most major Washington and Oregon utilities

Figure 10.6 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area. Other considerations, not depicted, include:

- Canada's similar winter- to summer-peak load ratio
- The increased ability of the Pacific Northwest hydro system in late June through early July compared to the hydro system's capability in the winter
- The reducing cost of solar and storage, which aligns very well with summer peak, but most be scaled up significantly to meet winter-peak needs.

Overall, each of these assessments includes very few new energy resources; any additions to the resource portfolio in the Pacific Northwest will only increase the surplus available during Idaho Power's peak operating periods. The regional resource adequacy assessments are consistent with Idaho Power's view that expanded transmission interconnection to the Pacific Northwest (i.e., B2H) provides access to a market with capacity for meeting its summer load needs and abundant low-cost energy, and that expanded transmission is critical in a future with automated energy markets such as the Western EIM and high penetrations of VERs.

IRP REPORT:

PREFERRED PORTFOLIO AND ACTION PLAN

11. PREFERRED PORTFOLIO AND ACTION PLAN

Preferred Portfolio

The portfolio development process for Idaho Power's 2021 IRP relies on an LTCE model first used in the 2019 IRP. The portfolio development process is explained in detail in Chapter 9.

In summary, for the 2021 IRP, the company developed a branching scenario analysis strategy to ensure that it had reasonably identified an optimal solution specific to Idaho Power and its customers. The company first identified six core resource portfolios with resource composition driven by the presence of B2H or Gateway West in each portfolio, and assumptions related to Jim Bridger exit dates. Once resource portfolios were generated, to evaluate future cost risks, the company performed cost analysis for the core resource portfolios under three different assumptions: planning case conditions for natural gas price and carbon cost, planning gas and no carbon cost, and higher-cost gas and carbon, as shown in Table 11.1.

Table 11.1 AURORA hourly simulations

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

The company also evaluated the qualitative risks, performed a stochastic risk analysis, and evaluated the reliability of each of the core portfolios (see Chapter 10).

Using the Preferred Portfolio (Base with B2H), the company developed additional portfolios to do the following:

1. Evaluate risk associated with different futures (discussed later in this Chapter)
2. Evaluate risk associated with different sensitivities
3. Evaluate the SWIP-North 500 kV project
4. Perform validation and verification tests on the Preferred Portfolio
5. Perform robustness sensitivities, cost tests, and timing tests on the B2H project

The Preferred Portfolio (Base with B2H) follows.

Table 11.2 Preferred Portfolio additions and coal exits (MW)

Base B2H (MW)									
Year	Gas	Wind	Solar	Storage	Trans.	DR	Coal Exits	EE Forecast	EE Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	105	0	20	-308	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	55	0	0	-175	27	0
2029	0	0	100	255	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	700	1,405	1,685	500	400	-841	428	12
Total	**4,289**								

The following items are included in Table 11.2:

- The 300 MW of DR showing in 2022 represents 380 MW of existing programs adjusted to the new program parameters to enhance their effectiveness. It is anticipated the program adjustments may result in some attrition.
- The addition of 1,405 MW of solar generation, including Jackpot Solar (120 MW) in 2023 and 785 MW of solar phased in from 2025 to 2028 to support the energy needs of large load customers.
- The conversion of Bridger units 1 and 2 (a combined 357 MW) is shown as a coal exit in 2023 and a gas addition in 2024. These units are exited at the end of their depreciable life in 2034. The 308 MW coal exit identified in 2025 includes both Valmy Unit 2 at 134 MW and Bridger Unit 3 at 174 MW.

- In addition to large storage projects, the Storage column includes 17 selections of 5 MW grid-located storage projects intended to defer transmission and distribution investments in addition to meeting system resource needs.
- The B2H transmission line is represented in the Trans. column as 500 MW in 2026.
- The Bridger Unit 4 coal exit is identified in 2028. At year-end 2028, Idaho Power will no longer have ownership of coal generation facilities. This is two years earlier than indicated in the 2019 IRP.
- The EE Forecast column shows a total of 428 MW of cost-effective energy efficiency measures that will be added to Idaho Power’s system to meet growing energy demand. These energy efficiency measures were identified in the energy efficiency Potential Assessment.
- In addition to the cost-effective energy efficiency measures shown in the EE Forecast column, additional bundles of energy efficiency were selected in the last two years of the plan. These are shown in the EE Bundles column.

Preferred Portfolio Compared to Varying Future Scenarios

Rapid Electrification

A rapid path towards electrification will require additional electrical infrastructure and resources to meet the increased demand for electricity. While the portfolio costs more overall, the cost per MWh served increases by less than 2%.

The differences between the Preferred Portfolio and the Rapid Electrification scenario can be seen in Table 11.3. Helpful insights can be gained by comparing the types and quantities of resources selected by each scenario and the timing of the selected resources.

Primarily, the first several years of the plan remain unchanged, with the exception of an additional 100 MW of wind generation identified in 2024. As the rapid electrification ramp becomes more significant, the Bridger Unit 4 exit is delayed one year, and additional resources are required to meet demand in the following years. Two sub-segments of Gateway West (shown in the table as GW1 and GW2) are also required to incorporate the additional renewable resources in the Rapid Electrification scenario. The comparison of the Preferred Portfolio and the Rapid Electrification scenario illustrates that small course corrections can be made along the way to adjust to a steep ramp towards electrification.

Table 11.3 Preferred Portfolio and Rapid Electrification scenario comparison

	Preferred Portfolio (MW)								Rapid Electrification (MW)							
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	115	0	20	-357	38
2024	357	700	0	5	0	0	0	25	357	800	0	5	0	0	0	25
2025	0	0	300	105	0	20	-308	27	0	0	300	105	0	0	-308	27
2026	0	0	215	0	500	0	0	28	0	0	215	0	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	5	0	0	0	27
2028	0	0	120	55	0	0	-175	27	0	0	120	105	0	0	0	27
2029	0	0	100	255	0	0	0	26	0	100	0	55	0	0	-175	26
2030	0	0	0	55	0	0	0	24	0	300	0	205	GW1	0	0	24
2031	0	0	0	55	0	0	0	24	0	0	100	105	0	0	0	24
2032	0	0	0	55	0	0	0	23	0	0	0	55	0	0	0	23
2033	0	0	0	100	0	0	0	22	0	0	0	55	0	0	0	22
2034	-357	0	100	150	0	0	0	21	-357	0	100	105	0	0	0	21
2035	0	0	100	305	0	0	0	20	0	0	100	405	0	20	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	0	0	16
2037	0	0	0	105	0	0	0	14	0	0	0	105	0	0	0	20
2038	0	0	100	155	0	20	0	12	0	0	100	205	0	20	0	12
2039	0	0	0	55	0	20	0	14	0	0	0	55	0	20	0	11
2040	0	0	0	55	0	20	0	19	0	200	100	5	GW2	40	0	10
Subtotal	0	700	1,405	1,685	500	400	-841	440	0	1,400	1,505	1,745	500	420	-841	448
Total	**4,289**								**5,178**							

Climate Change

Like the Rapid Electrification scenario, additional resources will be required to meet increased demand for electricity in the Climate Change scenario. In this scenario, the company modeled consistent demand (high) and water variability extremes (low water). These extremes are modeled for all years into the future and increase the need for more resources.

Additional renewable resources and battery storage are required to meet the requirements of the Climate Change scenario. The climate change modeling adjustments impact resource selections early in the plan with 100 MW of additional storage in 2023 and 200 MW of additional wind and solar in 2024. The comparison of the Preferred Portfolio and the Climate Change scenario illustrates that large additional quantities of resources (shown in the portfolio as wind and solar, paired with some storage) are required to meet system requirements if facing climate change related extremes on an annual basis.

Table 11.4 Preferred Portfolio and Climate Change scenario comparison

	Preferred Portfolio (MW)								Climate Change (MW)							
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	215	0	20	-357	54
2024	357	700	0	5	0	0	0	25	357	900	400	5	0	20	0	25
2025	0	0	300	105	0	20	-308	27	0	0	400	105	0	0	-308	27
2026	0	0	215	0	500	0	0	28	0	0	215	5	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	5	GW1	0	0	27
2028	0	0	120	55	0	0	-175	27	0	300	120	5	0	0	-175	27
2029	0	0	100	255	0	0	0	26	0	0	200	255	GW2	0	0	26
2030	0	0	0	55	0	0	0	24	0	100	100	5	0	0	0	24
2031	0	0	0	55	0	0	0	24	0	0	100	105	0	0	0	24
2032	0	0	0	55	0	0	0	23	0	0	0	5	0	0	0	23
2033	0	0	0	100	0	0	0	22	0	0	100	150	0	0	0	22
2034	-357	0	100	150	0	0	0	21	-357	0	100	105	0	0	0	21
2035	0	0	100	305	0	0	0	20	0	0	100	305	0	0	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	0	0	16
2037	0	0	0	105	0	0	0	14	0	0	100	105	0	0	0	14
2038	0	0	100	155	0	20	0	12	0	0	100	255	0	0	0	18
2039	0	0	0	55	0	20	0	14	0	0	0	55	0	0	0	17
2040	0	0	0	55	0	20	0	19	0	0	100	55	0	0	0	19
Subtotal	0	700	1,405	1,685	500	400	-841	440	0	1,300	2,505	1,795	500	340	-841	478
Total	**4,289**								**6,078**							

100% Clean by 2035

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

Table 11.5 Preferred Portfolio and 100% Clean by 2035 scenario comparison

	Base B2H (Base IPC Optimization)								100% Clean By 2035 (MW)								
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Nuclear	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	115	0	0	20	-357	24
2024	357	700	0	5	0	0	0	25	357	900	0	0	0	0	0	0	25
2025	0	0	300	105	0	20	-308	27	0	0	400	205	0	0	0	-308	27
2026	0	0	215	0	500	0	0	28	0	0	515	305	0	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	105	0	GW1	0	-175	27
2028	0	0	120	55	0	0	-175	27	0	200	320	205	0	0	20	0	27
2029	0	0	100	255	0	0	0	26	0	100	0	50	0	0	0	0	26
2030	0	0	0	55	0	0	0	24	-45	100	0	55	0	GW2	0	0	24
2031	0	0	0	55	0	0	0	24	-45	0	0	55	77	0	0	0	24
2032	0	0	0	55	0	0	0	23	-164	0	0	55	0	0	0	0	23
2033	0	0	0	100	0	0	0	22	-171	0	0	105	154	0	0	0	22
2034	-357	0	100	150	0	0	0	21	-693	0	100	155	154	0	0	0	21
2035	0	0	100	305	0	0	0	20	0	0	100	300	308	0	0	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	0	20	0	16
2037	0	0	0	105	0	0	0	14	0	0	0	100	0	0	0	0	20
2038	0	0	100	155	0	20	0	12	0	0	0	150	0	0	20	0	18
2039	0	0	0	55	0	20	0	14	0	0	0	50	0	0	40	0	14
2040	0	0	0	55	0	20	0	19	0	0	0	50	0	0	20	0	19
Subtotal	0	700	1,405	1,685	500	400	-841	440	-762	1,300	1,805	2,115	693	500	440	-841	451
Total	**4,289**								**5,702**								

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 below. The path to clean energy may not be linear and these assumptions were made to create a comparison scenario.

Because of the linear emission constraints imposed on the model in this scenario, additional solar is added early in the plan (compare solar in year 2025). The additional infusion of solar allows for an exit of Valmy Unit 2 one year earlier. This early increase in the quantity of solar ultimately requires an increase in access to renewables through the Gateway West transmission line.

Because existing natural gas generation resources are decreasingly utilized in the 100% Clean by 2045 scenario, approximately 400 MW of additional clean energy resources are selected (see the *Wind*, *Solar*, and *Storage* columns). While the more rapid replacement of carbon-emitting resources with flexible clean resources is not cost effective based on resource pricing forecasts produced today, it is the company's position that advances in technology will enable the cost-effective transition to meet this goal.

Achieving an earlier clean energy date includes the early addition of wind, solar, and storage, and the addition of nuclear as a flexible clean energy source later in the plan.

Table 11.6 Preferred Portfolio and 100% Clean by 2045 scenario comparison

	Preferred Portfolio (MW)								100% Clean By 2045 (MW)							
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	115	0	20	-357	24
2024	357	700	0	5	0	0	0	25	357	700	0	5	0	0	-134	25
2025	0	0	300	105	0	20	-308	27	0	0	900	200	0	0	-174	27
2026	0	0	215	0	500	0	0	28	0	0	215	0	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	5	GW1	0	-175	27
2028	0	0	120	55	0	0	-175	27	0	0	220	105	0	0	0	27
2029	0	0	100	255	0	0	0	26	0	0	0	55	0	0	0	26
2030	0	0	0	55	0	0	0	24	0	0	100	105	0	0	0	24
2031	0	0	0	55	0	0	0	24	0	0	0	5	0	0	0	24
2032	0	0	0	55	0	0	0	23	0	0	0	55	0	20	0	23
2033	0	0	0	100	0	0	0	22	0	0	0	55	0	20	0	22
2034	-357	0	100	150	0	0	0	21	-357	0	0	155	0	20	0	21
2035	0	0	100	305	0	0	0	20	0	0	100	305	0	20	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	20	0	16
2037	0	0	0	105	0	0	0	14	0	0	0	105	0	20	0	14
2038	0	0	100	155	0	20	0	12	0	0	0	155	0	20	0	12
2039	0	0	0	55	0	20	0	14	0	0	0	55	0	20	0	20
2040	0	0	0	55	0	20	0	19	0	0	0	55	0	20	0	19
Subtotal	0	700	1,405	1,685	500	400	-841	440	0	700	1,905	1,590	500	500	-841	446
Total	**4,289**								**4,800**							

CSPP Wind Renewal Low

The planning forecast for CSPP wind includes a renewal rate of 25% for contracts that will expire during the IRP timeframe. The CSPP Wind Renewal Low scenario assumes that none of the contracts renew. This increases the number or quantity of resources that must be acquired to meet increasing energy demand.

The focus of this comparison is on the Action Plan window (years 2021–2027) which holds very constant. The only identified difference is an additional 5 MW of storage in 2026. Later in the plan there are some bigger shifts as resources are selected to cover the loss of existing wind energy contracts. These shifts, first occurring in 2032, can be more effectively analyzed in later IRPs when more is known about whether the contracts will renew.

Table 11.7 Preferred Portfolio and CSPP Wind Renewal Low scenario comparison

	Preferred Portfolio (MW)								CSPP Wind Renewal Low (MW)							
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	115	0	20	-357	24
2024	357	700	0	5	0	0	0	25	357	700	0	5	0	0	0	25
2025	0	0	300	105	0	20	-308	27	0	0	300	100	0	20	-308	27
2026	0	0	215	0	500	0	0	28	0	0	215	5	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	5	0	0	0	27
2028	0	0	120	55	0	0	-175	27	0	0	120	55	0	0	-175	27
2029	0	0	100	255	0	0	0	26	0	0	100	250	0	0	0	26
2030	0	0	0	55	0	0	0	24	0	0	0	50	0	0	0	24
2031	0	0	0	55	0	0	0	24	0	0	100	105	0	0	0	24
2032	0	0	0	55	0	0	0	23	0	100	0	5	0	0	0	23
2033	0	0	0	100	0	0	0	22	0	0	0	105	0	0	0	22
2034	-357	0	100	150	0	0	0	21	-357	0	0	155	0	0	0	21
2035	0	0	100	305	0	0	0	20	0	0	100	305	0	20	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	0	0	16
2037	0	0	0	105	0	0	0	14	0	0	0	105	0	0	0	14
2038	0	0	100	155	0	20	0	12	0	0	100	155	GW1	0	0	21
2039	0	0	0	55	0	20	0	14	0	100	0	55	0	0	0	11
2040	0	0	0	55	0	20	0	19	0	100	0	50	0	0	0	16
Subtotal	0	700	1,405	1,685	500	400	-841	440	0	1,000	1,405	1,680	500	360	-841	443
Total	**4,289**								**4,547**							

CSPP Wind Renewal High

The planning forecast for CSPP wind includes a renewal rate of 25% for contracts that are expiring during the IRP timeframe. The CSPP Wind Renewal High scenario assumes that all wind contracts renew. The resource composition is different as the model selected more renewables, especially in the final year of the plan, and less storage in this scenario.

The focus of this comparison is on the Action Plan window (years 2021–2027), which is very similar across the portfolios. Differences show up in small increments in storage (see years 2024 and 2027) and demand response (see years 2024 and 2025). Both shifts are viewed as inconsequential as they represent less than 1% of the identified resource changes in the Action Plan. Later in the plan there are some bigger shifts identified. There is a decrease in storage that is replaced primarily with additional wind and solar resources. These shifts, first occurring in 2028 and 2029, can be reviewed in later IRPs when more is known about whether the contracts will renew.

Table 11.8 Preferred Portfolio and CSPP Wind Renewal High scenario comparison

	Preferred Portfolio (MW)								High Wind Renewal (MW)							
Year	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE	Gas	Wind	Solar	Storage	Trans.	DR	Exits	EE
2021	0	0	0	0	0	0	0	23	0	0	0	0	0	0	0	23
2022	0	0	0	0	0	300	0	24	0	0	0	0	0	300	0	24
2023	0	0	120	115	0	20	-357	24	0	0	120	115	0	20	-357	24
2024	357	700	0	5	0	0	0	25	357	700	0	0	0	20	0	25
2025	0	0	300	105	0	20	-308	27	0	0	300	105	0	0	-308	27
2026	0	0	215	0	500	0	0	28	0	0	215	0	500	0	0	28
2027	0	0	250	5	0	0	0	27	0	0	250	0	0	0	0	27
2028	0	0	120	55	0	0	-175	27	0	0	120	100	0	0	-175	27
2029	0	0	100	255	0	0	0	26	0	0	0	200	0	0	0	26
2030	0	0	0	55	0	0	0	24	0	0	0	55	0	0	0	24
2031	0	0	0	55	0	0	0	24	0	100	0	50	0	0	0	24
2032	0	0	0	55	0	0	0	23	0	0	0	50	0	0	0	23
2033	0	0	0	100	0	0	0	22	0	0	0	50	0	0	0	22
2034	-357	0	100	150	0	0	0	21	-357	0	100	150	0	0	0	21
2035	0	0	100	305	0	0	0	20	0	100	100	300	0	0	0	20
2036	0	0	0	55	0	0	0	16	0	0	0	55	0	20	0	16
2037	0	0	0	105	0	0	0	14	0	0	0	105	0	0	0	14
2038	0	0	100	155	0	20	0	12	0	0	100	150	GW1	0	0	12
2039	0	0	0	55	0	20	0	14	0	0	0	50	0	0	0	11
2040	0	0	0	55	0	20	0	19	0	200	300	5	0	20	0	10
Subtotal	0	700	1,405	1,685	500	400	-841	440	0	1,100	1,605	1,540	500	380	-841	428
Total	**4,289**								**4,712**							

Action Plan (2021–2027)

The 2021 IRP Action Plan is the culmination of the IRP process distilled down into actionable near-term items. The items identify milestones to successfully position Idaho Power to provide reliable, affordable, clean energy to our customers into the future.

The included resources will increase reliability on Idaho Power's electrical system to handle high-temperature events and operational contingencies.

The Action Plan associated with the Preferred Portfolio is driven by its core resource actions through 2027. These core resource actions include:

- Cost-effective energy efficiency measures in every year (2021–2027)
- The existing demand response programs redesign (2022)
- 120 MW of added solar PV capacity (2023)
- 100 MW of 4-hour Li-ion storage (2023)
- Distributed storage in 5 MW increments, 15 MW added in 2023, and 5 MW added in 2024, 2025, and 2027 for a total of 30 MW in the four identified years (2023, 2024, 2025, 2027)
- Two 20-MW increases in demand response, totaling 40 MW (2023, 2025)
- The conversion of the Bridger Coal units 1 and 2 to natural gas generation (2024)
- 700 MW of added wind (2024)
- An exit from Valmy Unit 2 and Bridger Unit 3 (2025)
- 100 MW of solar plus storage (2025)
- Additional solar to support large load customer energy needs
- B2H online (2026)

Action Plan (2021–2027)

Table 11.9 Action Plan (2021–2027)

Year	Action
2022	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state commissions.
2022	Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs.
2022–2023	Jackpot Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.
2022–2024	Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger units 1 and 2. The conversion is targeted before the summer peak of 2024.
2022–2025	Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.
2022–2025	Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.
2022–2025	Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.
2022–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2022–2027	Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.
2022–2027	Work with large-load customers to support their energy needs with solar resources.
2022–2027	Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.
2025	Exit Valmy Unit 2 by December 31, 2025.
2025–2026	Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

Resource Procurement

Idaho Power's capacity deficits identified for 2023, 2024, and 2025 described in previous sections of the IRP will require incremental generating capacity that exceeds the 80 MW applicability threshold for the OPUC's Resource Procurement Rules. To meet its resource needs in a timely manner and continue to provide reliable service, the company has requested relief[38] from the OPUC's Resource Procurement[39] requirements and for authorization to move forward with capacity resource procurements using an alternative acquisition method to meet the identified deficits in 2023, 2024, and 2025. The OPUC Resource Procurement Rules also contain an exception to their applicability based on the OPUC acknowledging an alternative acquisition method in the utility's IRP, which this section addresses.[40]

[38] In Idaho, IPC-E-21-41. In Oregon, UM 2210.

[39] The OPUC's Resource Procurement requirements are found in Division 89 of the Oregon Administration Rules.

[40] OAR 860-089-0100(3)(c).

Urgent Capacity Resource Need

Idaho Power's request for relief from resource procurement requirements is based on the company's rapid shift from resource sufficient to resource deficient—a change that came quickly and iteratively as the company received new information over the spring and summer of 2021. While Idaho Power's *Second Amended 2019 IRP* did not show a first capacity deficit until the summer of 2028, the 2021 IRP identifies capacity deficits beginning in 2023 and growing each year until 2026—when B2H is expected to be operational. Several factors have contributed to the notable change in the load and resource balance, including significant current third-party transmission constraints limiting wholesale market import purchases at peak, the ability of DR programs to meet peak load hours, planning margins and methodology modernization, and load growth exceeding previously forecasted expectations.

Changes in the Load and Resource Balance Since the 2019 IRP

Following development of the *Second Amended 2019 IRP*, the company conducted focused system reliability and economic analyses to assess the appropriate timing of a Valmy Unit 2 exit between 2022 and 2025. The result of the reliability and economic evaluations demonstrated that coal-fired operations Valmy Unit 2 through the end of 2025 is the most reliable and economic path forward.

The Valmy Unit 2 analysis, for reasons explained in further detail later, involved adjustment of the load and resource balance used in the *Second Amended 2019 IRP*. At this time, the 2021 IRP development was well underway, and the company updated the load and resource balance in the new IRP to include modifications to existing resource availability, as is standard when developing the load and resource balance as part of the IRP process. First, the company identified changes to its market purchase assumptions due to third-party transmission constraints. Additionally, the existing resource availability was revised to include updated thermal capacity and reduced DR capacity determined through the refinement of the planning margin calculation. The net change between the *Second Amended 2019 IRP* and the updated load and resource balance is a reduction of over 500 MW in available capacity each July during the 2022 through 2025 period. As a result of these changes known in May 2021, the company anticipated a capacity deficit of approximately 78 MW in 2023, assuming Valmy Unit 2 operations continue through 2025.

Detailed next are the factors leading to the initially identified capacity deficit of 78 MW in 2023.

Transmission Market Shifts and Constraints

In the *Second Amended 2019 IRP*, the company assumed Valmy Unit 2 could be replaced with capacity purchases from the south. However, market conditions have changed dramatically because of ripple effects stemming from the August 2020 energy emergency event in California. During this event, the west experienced a heat wave, increasing the demand for energy and causing several balancing authorities across the Western Interconnection to declare energy emergencies. Generation was insufficient to meet demand in California, and transmission capacity was strained, limiting the ability to import energy. As a result, CAISO was required to shed firm load to maintain the reliability and security of the bulk power system. Ultimately, the transmission constraints impacted Idaho Power's ability to use third-party transmission to import energy and meet load deficits.

Understanding the importance of transmission availability during times of high electricity demand, third-party marketing firms began reserving unprecedented amounts of firm transmission capacity just outside the border of Idaho Power's service area, significantly limiting the company's access to market hubs. Soon after the event, Idaho Power's own transmission service queue was flooded with multi-year requests totaling more than 1,000 MW, as of April 2021, looking to move energy from the Mid-C across Idaho Power's transmission system to the south.

While the company is able to reserve its own transmission for use by its customers, the transmission service requests just outside of Idaho Power's service area have added constraints to an already constrained market, limiting the company's access to capacity at Mid-C. Idaho Power tested the market availability with an RFP issued April 26, 2021, which ultimately validated the existence of these transmission system constraints. The RFP requested a market purchase with delivery at Idaho Power's border; however, no bids were received at any price point, further emphasizing the difficulty of importing energy under a constrained transmission system.

As a result of these recent and significant market changes, for the years 2023 through 2025, Idaho Power has reduced the transmission availability within the load and resource balance from approximately 900 MW in the 2019 IRP to approximately 700 MW in the 2021 IRP during the peak-load month of July.

Planning Margin Adjustments

As detailed in *Appendix C* of this report, Idaho Power modernized its planning margin approach and is using probabilistic methods (the "LOLE method") in the 2021 IRP to determine system needs and ensure reliability for all hours of the day on the company's system.

The LOLE method evaluates the capability of existing resources to meet peak demand through the determination of the ELCC. Use of the ELCC resulted in a change to the peak-serving capability of Idaho Power's existing resources, most notably the peak capacity contribution of DR. When analyzing the company's system on an hour-by-hour basis, the results indicate the ability of DR programs to meet peak-load hours under the changing dynamics of Idaho Power's system is significantly lower than previously assumed. This is primarily the result of increased solar resources on Idaho Power's system pushing net peak-load hours outside the current DR program window. The company has filed a request for modifications to its DR programs that, while making the programs more effective at meeting system needs, may result in lower DR participation.

Load Forecast Increases

Migration into Idaho Power's service area has exceeded forecasts, both during and after the recession; as customer additions were approximately 30% higher than prior expectations. In addition, several industrial customers, both existing and new, have made a sufficient and significant binding investment and/or interest indicating a commitment to locating or expanding operations in the company's service area. These drivers predict that Idaho Power's peak capacity by 2023 will grow faster than previously forecasted expectations.

Load and Resource Balance in the 2021 IRP

The load and resource balance used in the 2021 IRP (Table 10.7) incorporates the most up-to-date resource and load inputs. On the resource side, Idaho Power has applied the adjusted transmission assumptions, as well as the LOLE and ELCC methods described above. On the load side, Idaho Power has also included higher load growth expectations. The resulting capacity deficiency (approximately 101 MW in 2023, 186 MW in 2024, and 311 MW in 2025) clearly demonstrates the need for new capacity to meet those capacity deficits prior to the addition of B2H in 2026.

While these estimates reflect Idaho Power's best available information at the time of this IRP, the company's forecast capacity deficit beginning in 2023 could grow further. On November 9, 2021, the developers of Jackpot Solar informed Idaho Power that that global supply chain disruptions have raised concerns regarding Jackpot Solar's ability to achieve commercial operation by the dates identified in the approved agreement. If the Jackpot Solar project is delayed beyond summer 2023, or not built, Idaho Power will need approximately 40 MW of incremental peak capacity to meet projected customer demands.

2021 RFP

In order to meet its obligation to reliably serve customer load, and given the extremely short turnaround to construct a resource to meet deficits identified in 2023, 2024, and 2025, the company is currently conducting a competitive solicitation through an RFP seeking to acquire up to 80 MW of wind, solar, and storage combinations to meet the initially identified 78-MW capacity deficit in 2023.[41] The 2021 RFP seeks projects that can achieve commercial operation by June of 2023.

[41] The Oregon Procurement Rules do not apply to resources below 80 MW.

In the Spring of 2021, recognizing the urgency of the capacity deficit, the company assembled an interdisciplinary team to develop and process an RFP for 2023 peak capacity resources (RFP evaluation team). Idaho Power also retained a consultant, Black & Veatch Management Consulting, LLC, to assist the RFP evaluation team with development of the RFP and to provide guidance and evaluation support of the company's RFP process. The RFP evaluation team developed detailed criteria and a methodology for evaluating both price and qualitative attributes of a proposed resource. On June 30, 2021, the RFP evaluation team issued a formal request for competitive proposals for up to 80 MW of electric generating capacity.

A public Notice of Intent was released on May 20, 2021, to industry developers and media outlets and was posted to Idaho Power's website noticing Idaho Power's intent to release the RFP. Interested developers responded with an Intent to Bid by June 11, 2021. The "2021 All Source Request for Proposals for Peak Capacity Resources" was issued June 30, 2021, and solicited directly to the 38 developers who responded to the Intent to Bid. The RFP solicitation identified the purpose, key product specifications, proposal format, qualitative and quantitative evaluation criteria, template draft form term sheet, technical specifications, and additional requirements necessary to submit a qualifying proposal. The RFP solicitation also focused on the importance of having a project in service by June 2023. Thirteen proposals were submitted by third-party developers on August 11, 2021. The RFP evaluation process assesses both price and non-price attributes. Price attributes were weighted at 60% of the total valuation and non-price attributes were given a 40% weighting.

Once a winning bidder is selected and contractual documents are executed, the company, as it has done in the past, will bring the proposed generation acquisition to the IPUC for review in a Certificate of Public Convenience and Necessity (CPCN) proceeding to establish both the need and expected cost of the procurement. The required Idaho CPCN process, as well as the subsequent rate-making proceedings in both Idaho and Oregon, will provide considerable oversight of the procurement process, and ensure low-cost, reliable resource acquisitions for customers—as Idaho Power has done for the company's more than 100-year history.

Because the 2021 RFP seeks resources that are not more than 80 MW, the RFP is not subject to the Oregon Resource Procurement rules.[42] Idaho Power is also, in parallel, investigating different configurations of company-owned and constructed battery storage systems, modifications to existing DR programs, and pursuing other short-term market solutions to meet the forecasted capacity deficits. However, these efforts will not be enough to meet the rapidly evolving and dynamic forecasted capacity deficits. Indeed, since issuing the 2021 RFP earlier

[42] OAR 860-089-0100(1)(a)

this year, the expected capacity deficit for 2023 has increased from 78 MW to 101 MW—the number that is now included in the 2021 IRP.

2022 All Source RFP

Given the revised load and resource balance that is used in the 2021 IRP, Idaho Power will be issuing another RFP seeking generation resources to meet the additional capacity deficits identified for 2024 and 2025. The proposed acquisitions are necessary and required in a dynamic energy landscape in order to continue to provide reliable and adequate electric service to Idaho Power's customers starting in the summer of 2024 and into the future. There is insufficient time to complete a procurement process contemplated by the Oregon Resource Procurement process that will meet the identified deficits in 2024 and 2025.
Although Idaho Power has requested a waiver of the OPUC's competitive billing rules to allow the company to conduct a more expedited process, the proposed RFP will be conducted in substantially the same manner as that used for the 2021 RFP and will result in a fair, objective, and transparent procurement process.

Alternative Acquisition Method

Idaho Power will conduct an RFP to obtain competitive pricing and identify the best resource(s) to ensure adequate, reliable, and fair-priced service to its customers. To provide an opportunity for contemporaneous oversight of the upcoming RFP, the company also proposes to submit a filing at the conclusion of the RFP that will allow the IPUC, OPUC, and stakeholders to review the procurement process and results. Idaho Power's proposed filing in Oregon would be akin to the CPCN process that will be used in Idaho[43] to authorize the company to move forward with the acquisition of the resource(s) selected in the RFP. The company's filing would present the results of the RFP to the commissions for independent evaluation and request acknowledgment of the selected resource(s).

Idaho Power's proposal recognizes the value of commission and stakeholder participation in and review of the company's procurement process but will not compromise the expedited timeline required to ensure that the resource(s) selected in the RFP will be in-service and capable of meeting Idaho Power's resource needs beginning in 2023.

[43] Notably, the state of Oregon does not have a corresponding requirement for the issuance of a CPCN for supply-side or generation resources like Idaho. *Idaho Code* § 61-526.

Conclusion

The 2021 IRP provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. The B2H transmission line continues in the 2021 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.

The cost competitiveness of wind, PV solar, and storage is another notable theme of the 2021 IRP. The Preferred Portfolio for the 2021 IRP includes a total of 700 MW of wind, 1,405 MW of solar, and 1,685 MW of storage. Idaho Power's IRP analysis indicates these resources allow access to cost-competitive energy and further positions the company well to achieve its long-term clean energy goals.

The 2021 IRP indicates favorable economics associated with the conversion of Bridger Coal units 1 and 2 from coal to natural gas operation, as well as the exit from two of the remaining three coal generating units by the end of 2025. The exit from the remaining unit at the Jim Bridger facility was determined to be economical and achievable by the end of 2028. This strategy is consistent with Idaho Power's long-term clean energy goals and transition from coal generation. The B2H transmission line is critical to enabling the exit from coal generation.

Idaho Power has an important obligation to deliver reliable and affordable electricity to customers, which cannot be compromised as it strives to achieve its clean energy goals. That obligation also underscores the need to continue to evaluate coal units' value in providing flexible capacity necessary to successfully integrate high penetration of VERs. Furthermore, the company recognizes the evaluation of flexible capacity, and the possibility of flexibility deficiencies arising because of coal-unit exits, may require the Preferred Portfolio's flexible capacity resources to be online sooner than planned.

Idaho Power strongly values public involvement in the planning process and thanks the IRPAC members and the public for their contributions throughout the 2021 IRP process. The IRPAC discussed many technical aspects of the 2021 resource plan, along with a significant number of political and societal topics at the meetings. Idaho Power's resource plan is better because of the contributions from IRPAC members and the public.

Idaho Power prepares an IRP every two years. The next plan will be filed in 2023. The energy industry is expected to continue undergoing substantial transformation over the coming years, and new challenges and questions will be encountered in the 2023 IRP. Idaho Power will continue to monitor trends in the energy industry and adjust as necessary.