IDAHO POWER
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED—REDLINE

OCTOBER • 2020

BALANCING OUR ENERGY NEEDS • TODAY AND TOMORROW

SAFE HARBOR STATEMENT

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Glossary of Acronyms

A/C—Air Conditioning
AC—Alternating Current
ACE—Affordable Clean Energy
AECO—Alberta Energy Company
AFUDC—Allowance for Funds Used During Construction
AgI—Silver Iodide
akW—Average Kilowatt
aMW—Average Megawatt
ATB—Annual Technology Baseline
ATC—Available Transfer Capacity
B2H—Boardman to Hemingway
BLM—Bureau of Land Management
BPA—Bonneville Power Administration
CAA—*Clean Air Act of 1970*
CAISO—California Independent System Operator
CAMP—Comprehensive Aquifer Management Plan
CBM—Capacity Benefit Margin
CCCT—Combined-Cycle Combustion Turbine
CEM—Capacity Expansion Model
cfs—Cubic Feet per Second
CHP—Combined Heat and Power
CHQ—Corporate headquarters
Clatskanie PUD—Clatskanie People's Utility District
CO_2—Carbon Dioxide
COE—United States Army Corps of Engineers
CPP—Clean Power Plan
CSPP—Cogeneration and Small-Power Producers
CWA—*Clean Water Act of 1972*
DC—Direct Current
DOE—Department of Energy
DPO—Draft Proposed Order
DSM—Demand-Side Management
EFSC—Energy Facility Siting Council
EGU—Electric Generating Unit
EIA—Energy Information Administration
EIM—Energy Imbalance Market
EIS—Environmental Impact Statement
EPA—Environmental Protection Agency

ESA—*Endangered Species Act of 1973*
ESPA—Eastern Snake River Plain Aquifer
ESPAM—Enhanced Snake Plain Aquifer Model
F—Fahrenheit
FCRPS—Federal Columbia River Power System
FERC—Federal Energy Regulatory Commission
FPA—*Federal Power Act of 1920*
FWS—US Fish and Wildlife Service
GHG—Greenhouse Gas
GPCM—Gas Pipeline Competition Model
GWMA—Ground Water Management Area
HB—House Bill
HCC—Hells Canyon Complex
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
IPMVP—International Performance Measurement and Verification Protocol
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
LDC—Load-Duration Curve
Li—Lithium Ion
LiDAR—Light Detection and Ranging
LNG—Liquefied Natural Gas
LOG—Low Oil and Gas
LOLP—Loss-of-Load Probability
LTCE—Long-Term Capacity Expansion
LTP—Local Transmission Plan
m^2—Square Meters
MATL—Montana–Alberta Tie Line
MOU—Memorandum of Understanding

MSA—Metropolitan Statistical Area
MW—Megawatt
MWAC—Megawatt Alternating Current
MWh—Megawatt-Hour
NEEA—Northwest Energy Efficiency Alliance
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NLDC—Net Load-Duration Curve
NOx—Nitrogen Oxide
NPV—Net Present Value
NREL—National Renewable Energy Laboratory
NTTG—Northern Tier Transmission Group
NWPCC—Northwest Power and Conservation Council
NYMEX—New York Mercantile Exchange
O&M—Operation and Maintenance
OATT—Open-Access Transmission Tariff
ODEQ—Oregon Department of Environmental Quality
ODOE—Oregon Department of Energy
OEMR—Office of Energy and Mineral Resources
OFPC—Official Forward Price Curve
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statute
~~P14—Portfolio 14~~
pASC—Preliminary Application for Site Certificate
PCA—Power Cost Adjustment
PGE—Portland General Electric
PM&E—Protection, Mitigation, and Enhancement
PPA—Power Purchase Agreement
PURPA—*Public Utility Regulatory Policies Act of 1978*
PV—Photovoltaic
QA—Quality Assurance
QF—Qualifying Facility
RAAC—Resource Adequacy Advisory Committee
REC—Renewable Energy Certificate
RFP—Request for Proposal
RH BART—Regional Haze Best Available Retrofit Technology
RICE—Reciprocating Internal Combustion Engine
RMJOC—River Management Joint Operating Committee
ROD—Record of Decision
ROR—Run-of-River
ROW—Right-of-Way
RPS—Renewable Portfolio Standard

RTF—Regional Technical Forum
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SMR—Small Modular Reactor
SNOWIE—Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment
SO_2—Sulfur Dioxide
SRBA—Snake River Basin Adjudication
SRPM—Snake River Planning Model
T&D—Transmission and Distribution
TRC—Total Resource Cost
UAMPS—Utah Associated Municipal Power Systems
US—United States
USBR—United States Bureau of Reclamation
USFS—United States Forest Service
VER—Variable Energy Resources
VRB—Vanadium Redox-Flow Battery
WECC—Western Electricity Coordinating Council

Second Amended 2019 IRP Executive Summary

Introduction and Background

~~Idaho Power filed its *2019 Integrated Resource Plan* on June 28, 2019. Based on comments received during the development of the 2017 IRP, Idaho Power elected to use the AURORA software's Long Term Capacity Expansion (LTCE) modeling capability to develop portfolios for the 2019 IRP, reflecting a departure from its long-standing methodology of manually developing portfolios to eliminate resource deficiencies identified through a load and resource balance. The filing of the 2019 IRP represented the first iteration of the company's resource plan utilizing a computer-based model to develop future resource portfolios.~~

~~For reasons described in detail in this Executive Summary, following the filing of the 2019 IRP Idaho Power identified the need to suspend the processing of its plan due to concerns with the modeling output. Consequently, on July 19, 2019, the company filed letters with both the Idaho and Oregon public utilities commissions providing notification that additional time was needed to perform supplemental analysis to confirm the 2019 IRP's conclusions and findings. In November 2019, Idaho Power provided notice that it would file its Amended 2019 IRP no later than January 31, 2020.~~

Idaho Power's Integrated Resource Plan (IRP) for 2019—detailed herein and referenced as the *Second Amended 2019 IRP*—is the culmination of a deep examination of the company's IRP modeling processes and practices, as well as a holistic assessment of a wide range of potential resource futures. Idaho Power's final Preferred Portfolio represents the best combination of least-cost and least-risk resource actions for customers, while furthering the company's efforts to achieve its commitment to reliably providing 100-percent clean energy by 2045.

The final 2019 Preferred Portfolio is a manually optimized scenario constructed under planning gas and planning carbon conditions with the selection of the Boardman to Hemingway (B2H) transmission line. As such, the Preferred Portfolio is referenced as PGPC B2H (1). This portfolio started with similar resources to those selected in the Western Electricity Coordination Council (WECC)-optimized Portfolios 13 and 14, which were grouped together for the manual adjustment process due to their similarities.

This document ~~reflects the culmination of the supplemental analysis performed by Idaho Power following the submission of its initial 2019 IRP in June. It should be noted that the changes detailed in this Executive Summary impacted multiple phases of IRP preparation; therefore, this document~~ and the associated appendices are intended to replace both the initial ~~documents~~IRP, filed on June 28, 2019~~ in their entirety~~, as well as the Amended 2019 IRP, filed on January 31, 2020. For the sake of clarity, the company believes ~~that~~ a new standalone set of documents offers a clear representation of the 2019 IRP's findings and conclusions, rather than attempting to provide an addendum ~~that attempts to identify~~detailing elements that changed and those that did not. .

~~Cause for Filing Suspension~~

~~As discussed in detail in this document, the LTCE capability of the AURORA model selects from a variety of supply- and demand-side resource options to develop portfolios optimal for given alternative future scenarios, with the objective of meeting a 15-percent planning margin and regulating reserve requirements associated with balancing load and intermittent resources output. The model can also simulate retirement of existing generation units, and build resources that are economic absent a defined capacity need.~~

~~While the 2019 IRP was in development, a time-limited opportunity to purchase the output of a 120 megawatt (MW) solar facility (Jackpot), with the option of an additional 100 MW (Franklin), was presented to Idaho Power. Because Idaho Power was in the development phase of the 2019 IRP, the basic structure of the Jackpot and Franklin power purchase agreement (Solar PPA) was included in the IRP's LTCE analysis. As detailed in Idaho Power's filed 2019 IRP, the LTCE model selected both Jackpot and Franklin as optimal resources in the company's preferred portfolio.~~

~~Idaho Power's determination that additional analysis was needed for the 2019 IRP originated in the processing of the case to approve the Solar PPA. While performing analyses necessary to support approval of the PPA in that case—and what ultimately led to the conclusion that additional investigation was warranted—Idaho Power discovered that when it forced the model to make a decision that was counter to the optimized result, overall portfolio costs for Idaho Power decreased in certain cases. Based on these counterintuitive results, Idaho Power filed the aforementioned request to suspend processing of its 2019 IRP and performed a comprehensive review of the LTCE methodology and the corresponding modeling inputs to identify the potential cause and ensure its analyses developed the most accurate results possible.~~

~~LTCE Modeling Review~~

~~First, the Company identified the regional LTCE modeling parameters as one possible area driving these counterintuitive results. In order to model appropriate market conditions for the Western Electricity Coordinating Council (WECC), the LTCE model logic optimizes resource build-out portfolios for the entire region, not just Idaho Power. Consequently, Idaho Power was concerned that the WECC-optimized LTCE runs were optimizing resources for the region, but not necessarily for Idaho Power and its customers.~~

~~To test this, Idaho Power performed a new set of LTCE runs where it first optimized the 20-year future for the WECC, then locked down the WECC resource buildout and re-ran the LTCE model specifically calibrated to optimize Idaho Power's service area. However, these modified runs did not yield consistently lower cost results for Idaho Power than the prior runs optimized for the WECC. Based on these results, Idaho Power determined that a fully computer-based optimization was not a feasible method at this time for ensuring that the modeling reasonably identified the least-cost, least-risk portfolio for Idaho Power's customers.~~

~~In place of fully computer-based modeling, Idaho Power developed a hybrid solution in which it utilized the WECC-optimized LTCE model to develop 24 initial portfolios, then performed a manual process to modify a subset of the top-performing portfolios, with the ultimate goal of improving upon the modeled results and arriving at least-cost, least-risk portfolio specific to~~

~~Idaho Power. This manual process generally evaluates the level of reserves on the system on an annual basis, then modifies resource additions and retirements manually to see if a more economically optimal result can be achieved. This process, discussed in detailed in Chapter 9, focuses on the retirement dates for units at the Jim Bridger Coal Plant (Bridger), to ensure the shutdown dates of these units are developed to yield the best possible economic and reliability outcome for Idaho Power and its customers.~~

~~Modeling Input Review~~

~~In addition to the reevaluation of the LTCE model and the implementation of the manual adjustment process, Idaho Power performed a comprehensive review of all modeling inputs feeding into the development of the 2019 IRP. Through this review, Idaho Power identified eight modifications to its modeling inputs to ensure more accurate modeling results. These results, described in more detail in the sections that follow, include: 1) the addition of renewable energy certificate (REC) values for Jackpot Solar, 2) updating transmission interconnection costs for Jackpot Solar, 3) removing Franklin Solar from the list of available resources, 4) correcting the online date for Jackpot Solar, 5) allowing the model to correct the peak credit for new solar if Jackpot Solar is not selected, 6) introducing costs associated with natural gas supply expansion, 7) returning to the previous method of utilizing an after-tax discount rate for net present value calculations, and 8) including third party transmission revenues associated with the Boardman-to-Hemingway transmission line (B2H).~~

~~*1. REC Values for Jackpot Solar*~~

~~Through Idaho Power's comprehensive review of all modeling inputs, it was determined that potential REC revenues associated with the Jackpot Solar PPA were inappropriately excluded from Idaho Power's costing models. Therefore, the amended analysis includes potential benefits associated with REC sales from the Jackpot Solar PPA based upon the same REC value forecast applied to other solar resources analyzed in this IRP.~~

~~*2. Transmission Interconnection Costs for Jackpot Solar*~~

~~Prior to the time that Jackpot Solar approached Idaho Power with a proposal to sell its generation to Idaho Power, Jackpot Solar had completed the interconnection study process as a non-PURPA, independent power producer pursuant to the Open Access Transmission Tariff (OATT). The project was studied for interconnection as an Energy Resource (ER), which looks only at required facilities and upgrades needed to connect to Idaho Power's system, without looking at the deliverability requirements or upgrades required to deliver its output to a particular location or load. Such evaluation and/or studies would be done subsequently at the time when the project made a request to deliver its output, as a point-to-point transmission service request, or if selling to Idaho Power as an Idaho Power Designated Network Resource. Pursuant to its request, the project was initially studied as an ER identifying a new substation at the point of interconnection that connected to the Midpoint-NV/ID Border 345-kV line in a tap configuration.~~

~~Jackpot subsequently approached Idaho Power proposing to sell the project's output to Idaho Power, and Idaho Power eventually entered into a PPA with the developer, thus changing the status of the project and the type of interconnection. Once Idaho Power had a contract to take the generation from the project, it required Idaho Power's merchant function to submit a~~

~~Transmission Service Request for Network Integration Transmission Service, which required the project to be studied for the deliverability of its output as an Idaho Power Network Resource ("NR"). The requested transmission service requires the transfer of the project's energy across Idaho Power's internal transmission system to serve Idaho Power's native load. As a result, and in order to provide the requested Network Integration Transmission Service, a more robust ring-bus configuration was required, as opposed to the previously identified tap configuration for ER service, totaling approximately $11 million in network upgrades in order to serve Idaho Power load as a Designated Network Resource. Due to the project's status as a non-PURPA NR, the identified Network Upgrades are funded by the Transmission Provider, Idaho Power Transmission, as required by the OATT. Based on this change, the company updated cost inputs associated with Jackpot Solar to reflect the incremental transmission investment that would be funded by Idaho Power.~~

~~3. Removal of Franklin Solar~~

~~On October 23, 2019, Idaho Power filed comments in IPUC Case No. IPC-E-19-14, updating the IPUC that on October 18, 2019, it delivered notice stating that the company elected not to exercise its right and option to purchase the 100 MW of additional output related to the Franklin Solar project. Because Idaho Power elected to forego this project, it was removed from the stack of available resources within the LTCE model.~~

~~4. Corrected Online Date for Jackpot Solar~~

~~The current scheduled operating date for Jackpot Solar is December 1, 2022. In initial modeling runs, the selection of a 2022 operating year within the model resulted in a scenario in which generation started at the beginning of the year, or eleven months prior to the scheduled operating date indicated in the contract. To better align the modeled online date with the expected online date from the contract, the modeled year was adjusted to 2023 with generation output starting January 1, 2023, or one month after the scheduled operating date.~~

~~5. Peak Capacity Credit for Solar Resources~~

~~The solar peak-hour capacity credit on a by-project basis is provided in tabular and graphic format in the Supply-Side Resource Data section of the *Amended 2019 IRP Appendix C: Technical Report*. In the initial application, Jackpot Solar comprised projects 1 through 3, Franklin Solar comprised projects 4 and 5, and generic solar comprised projects 6 through 24. In the latest portfolios developed by AURORA, Franklin Solar was removed and generic solar now comprises projects 4 through 24.~~

~~AURORA has the ability to individually model the capacity value for each project, but these values are directly assigned. Therefore, if Jackpot is not selected, the values for the other projects remain as assigned. The current version of AURORA lacks the capability to dynamically adjust peak-hour solar capacity contributions when Jackpot is not selected, but other solar resources are selected in later years. It should be noted, however, that the impact of this modeling limitation in AURORA is relatively small, as the difference in capacity value between the average of projects 1 through 3 (Jackpot Solar) and Project 4 (the next project in the queue) is only 2.9 MW (see the *Amended 2019 IRP Appendix C: Technical Report*).~~

~~6. B2H Transmission Revenue Credits~~

~~For modeling purposes in the filed June 2019 IRP, transmission revenue credits associated with B2H were excluded because Idaho Power initially felt that a conservative approach was appropriate for evaluating this resource. These credits reflect the estimated incremental transmission wheeling revenue from non-native load customers as a result of B2H.~~

~~However, through the Idaho Power's comprehensive re-evaluation of all inputs into its IRP modeling runs, it determined that it is appropriate to include all relevant cost and benefit information associated with each resource type, including incremental transmission revenues from B2H. Therefore, portfolios developed as part of the Amended 2019 IRP now include these amounts, which is consistent with the methodology utilized in the 2017 IRP.~~

~~7. Discount Rate Modification~~

~~The discount rate used to develop the Amended 2019 IRP was reduced from 9.59 to 7.12 percent, reflecting the after-tax weighted-average cost of capital (WACC). The original discount rate used in the 2019 IRP financial modeling utilized Idaho Power's WACC plus a tax gross-up for the equity-financed portion of the overall costs. This represented a change from prior IRPs, in which the traditional WACC was used for all discounting calculations. While both methods (pre-tax and post-tax) are reasonably considered and analytically sound, Idaho Power originally believed the higher discount rate may better align with the customer cost perspective, as it reflects the total financing costs customers will actually pay through rates.~~

~~However, while conducting the supplemental IRP analyses following the filing of the 2019 IRP, Idaho Power observed that the use of the higher discount rate was having a material impact on the timing and nature of investments included in the various portfolio runs, particularly those portfolios modeled under expected case assumptions. It was not Idaho Power's intent for the change in discount rate methodology to serve as a major driver of changes to its long-term planning outcomes, especially at a time when other significant modifications to the analytical framework were being implemented, such as the introduction of computer-based LTCE modeling. As a result, Idaho Power has returned to the prior practice of applying its internal after-tax WACC as the discount rate for the Amended 2019 IRP until more evaluation and vetting of alternative methodologies can occur. This approach remains consistent with prior years' IRPs and may be more understandable as a general indicator of value in the near-term.~~

~~8. Natural Gas Pipeline and Capacity Considerations~~

~~While reviewing the modeling inputs, Idaho Power determined that certain costs associated with the procurement of incremental natural gas supply should be incorporated into the model; therefore, additional fixed costs associated with future natural gas resources have been added. These modifications, discussed in depth in Chapter 7, reflect the cost of ensuring pipeline transportation capacity utilizing existing infrastructure, as well as the cost of pipeline expansion if projected gas generation exceeds a certain threshold.~~

Regulatory History

Idaho Power filed its original IRP with the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC) on June 28, 2019 and its Amended 2019 IRP on

January 31, 2020. In June of 2020, the Company identified necessary changes in the Amended 2019 IRP, which prompted Idaho Power to initiate a comprehensive review of its modeling and analysis. This final 2019 IRP document—the *Second Amended 2019 IRP*—reflects the culmination of prior IRP learnings and subsequent adjustments related to the recent IRP review process. The IRP review and outcomes are outlined below, while a more detailed account is provided in the separate *2019 IRP Review Report*, filed alongside the *Second Amended 2019 IRP*.

Comprehensive 2019 IRP Review Process

Idaho Power's 2019 IRP review, conducted in July 2020, involved a comprehensive four-step process to deconstruct and examine all aspects of this IRP cycle, from model inputs to model outputs. To conduct this review, the company formed a multidisciplinary team (IRP Review Team) of subject matter experts from its Planning, Engineering and Construction and Power Supply departments and Finance departments. Additional support and consultation were provided throughout each step of the process by members of the company's Internal Audit and Regulatory Affairs departments to ensure a consistent and methodical review.

The company identified several objectives for the 2019 IRP review:

- Provide clarity over the entire IRP development process
- Verify the accuracy and modeling of key inputs
- Validate model outputs
- Make processes more visible across the company
- Create consistency in the manner each step is performed
- Ensure compliance with industry standards/regulations

Detailed in the following sections are the specific actions taken within each step of the review process:

Input Data and Source Review

The IRP Review Team began with a full examination of input data related to the IRP process. A total of 11 sub-teams were formed, each with appropriate subject matter experts, to examine individual categories of input data used in the company's long-term planning tool, the AURORA model. The following are categories of inputs reviewed:

- Forecast inputs for natural gas price (sub-team 1), hydrologic system and stream flow (sub-team 2), and the company's load forecast (sub-team 3)
- Supply-side inputs related to the company's coal units (sub-team 4), natural gas plants (sub-team 5), and co-generator & small power producers and PURPA contracts (sub-team 6)

- Demand-side inputs related to demand response and energy efficiency programs (sub-team 7)
- Transmission system-related inputs (sub-team 8), including those related to the B2H project (sub-team 9)
- Financial inputs and Future Supply-Side Resources (sub-team 10) related to items such as the Weighted Average Cost of Capital, fixed and operations and maintenance (O&M) costs, property tax treatment, and modeled future supply-side resources
- Reliability inputs (sub-team 11) related to the company's regulating reserve requirements

The sub-teams reviewed all aspects of these inputs, including cross-verification against source materials, examination and investigation of supporting models that produce AURORA input data (e.g., two hydrologic and streamflow models), review of regulatory decisions and orders that determined specific AURORA input treatment, and evaluation of internal methodologies and processes for developing Idaho Power-specific data (e.g., the company load forecast).

Feeding Data into the Model

In the second step of the review, the IRP Review Team examined the ways in which the above inputs are incorporated into the AURORA model. This step involved validating any necessary data transformations or conversions to make the inputs "model ready." For instance, some inputs must be converted from one unit to another to meet AURORA specifications. The IRP Review Team ensured that all such conversions and transformations were conducted properly and that data fed into AURORA were accurate.

Model Settings and Processing

Next, the IRP Review Team analyzed how the AURORA model treats data within the model itself—referred to as modeling logic. For this step, the team worked in consultation with Energy Exemplar, the developers of the AURORA model, to further verify model processes and specifications. Additionally, this step of the review involved a thorough assessment of AURORA system settings to ensure that data within the model were interacting in a logical manner and consistent with Idaho Power's knowledge of its own system and resources.

Model Output Review

Finally, the IRP Review Team examined the consistency and accuracy of the AURORA model outputs to ensure that the model was producing logical and consistent results.

Ultimately, the company believes that this review process has provided increased transparency into the complexities of the IRP development and has provided valuable lessons and insights that will be applied to future IRP processes.

IRP Review Results

Through the above four-step review process, the company identified several appropriate changes to model inputs and treatment of data within the model. Some of these changes were identified by the company prior to the review process and were the basis for the July 1, 2020, Motion to

Suspend. Each of these identified issues were carefully documented and resolved, as more fully described in the *2019 IRP Review Report*. A summary of the identified adjustments is shown below.

Coal Plant Inputs & Cost Treatment

Idaho Power identified adjustments related to the treatment of its coal plants in the IRP modeling process:

Jim Bridger Power Plant (Bridger)

1. The financial assumptions used to calculate the revenue requirement for the Bridger coal units did not match the financial assumptions used to calculate the revenue requirement for all supply-side resources. These assumptions were reviewed, corrected, and now are consistent with the treatment of other supply-side resources.

2. In the portfolio costing, AURORA truncated fixed costs at the point a Bridger unit is shut down, resulting in avoided O&M and forecasted capital additions. As a result, the remaining net book value of the unit at the time of its exit must be added back to the total portfolio cost. This adjustment was made, and portfolio costs reflect the appropriate NBV.

3. In the remaining net book value added back to the total portfolio cost, common facility costs were truncated for Bridger units that retired early. As a result, the truncated common facility costs must be included in the remaining net book value added back to the total portfolio cost. This adjustment was made, and portfolio costs reflect the appropriate NBV.

4. Idaho Power's share of the variable operations and maintenance (O&M) costs associated with the Bridger units should have been modeled as one-third of the total projected costs. This adjustment was made and now reflects the appropriate Idaho Power one-third share.

5. The fixed cost rates for Bridger Unit 4 were inadvertently referencing the table of fixed costs for Bridger Unit 3 within AURORA. This adjustment was made and the fixed cost rates for Unit 4 now reference the correct table.

Valmy Fixed Costs

1. The financial assumptions to calculate the incremental revenue requirement for Valmy did not match the financial assumptions used to calculate the revenue requirement for all supply-side resources.

2. The Valmy fixed O&M rate needed to be updated to adequately capture savings associated with the exit of Unit 2 prior to 2025.

It should be noted that after making these adjustments, Idaho Power identified the potential for additional savings associated with a Unit 2 exit as early as 2022. This issue is discussed in greater detail in the Valmy Unit 2 Exit Date section of Chapter 1.

Bridger, Valmy and Boardman Variable O&M

The variable O&M rates for Bridger, Valmy, and Boardman should have been input as a nominal 2012 amount and escalated to a 2019 amount rather than reflected as a 2019 nominal amount, as per the AURORA model input requirements. This adjustment was made, and the variable O&M rates entered into the model reflect the 2012 nominal values.

Natural Gas Plant Inputs

Three adjustments were identified in the review of various natural gas inputs:

1. Natural Gas Transport Costs: Variable transport costs were inadvertently not included in the model. This small cost stream was reviewed for accuracy and added to the natural gas input costs.

2. Natural Gas Peaker Plant Start-Up Costs: The maintenance costs associated with natural gas peaker plants were captured only as a variable cost applied directly to the runtime of the unit. Startup costs were not included, which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected. After identifying the issue, the startup costs were entered, resulting in a reduction in peaker dispatch and reflecting a logical and expected outcome.

3. Langley Gulch Ramp Rate: The ramp rate for the Langley Gulch natural gas plant was set for 100 percent. Upon review, this rate was reduced to 60 percent to better reflect actual plant operations.

Demand Response

In the review process, Idaho Power tested an alternative approach to modeling demand response (DR). In prior versions of the 2019 IRP, expanded DR programs were modeled such that dispatch of said programs would only execute when Idaho Power’s resources were in deficit. That is, expanded DR was being treated as a last-resort resource. In the IRP review, which analyzed the treatment of all resources, Idaho Power opted to treat DR as a resource to offset peak load. While the prior approach was not incorrect, the revised approach is more consistent with the way Idaho Power’s DR programs work in practice.

Financial Assumptions and Future Supply-Side Resources

Two adjustments were identified related to the financial assumptions of new resource additions in AURORA:

1. Property tax rates were outdated. Upon review, the rates were adjusted to reflect information available when the 2019 IRP analysis was originally performed.

2. Annual insurance premium rates inadvertently reflected the wrong decimal place value. This issue was corrected during the review process.

Transmission Inputs

In the review process, two categories of necessary adjustments were identified related to transmission characteristics:

1. The loss and/or wheeling rates applied to some transmission lines required adjustment. Rates were adjusted as appropriate and now reflect correct information.

2. The following adjustments to transmission capacity were identified in the review process and have been entered into AURORA:

   a. Following exit from the Boardman coal plant, available transmission capacity was understated (53 megawatts (MW)).

   b. The Idaho Power transmission export capacity on Boardman to Hemingway was understated (85 MW).

   c. Idaho to Northwest west-to-east capacity in January through May and September through December post July 2026 was understated (200 MW).

   d. The transmission capacity on Bridger West was adjusted to reflect Idaho Power's ownership share.

Reliability Inputs

Two adjustments were identified:

1. The solar and wind allocation factors for downward regulation referenced the upward allocation factors. These allocation factors are now referencing downward regulation.

2. Valmy Unit 2 was modeled with the ability to provide regulation reserves, but the unit cannot provide regulation reserves. This adjustment was made, and Valmy Unit 2 is now modeled appropriately.

Impact to Preferred Portfolio

While the review process helped identify a number of important adjustments and refinements to the IRP process, the Preferred Portfolio remains very similar to the portfolio selected in the Amended 2019 IRP.

The final 2019 Preferred Portfolio is a manually optimized scenario conducted under planning gas and planning carbon conditions with the selection of the Boardman to Hemingway (B2H) transmission line. As such, the Preferred Portfolio is referenced as PGPC B2H (1). This portfolio was built off the combination of Western Electricity Coordination Council (WECC)-optimized Portfolios 13 and 14, which were grouped together for the manual adjustment process due to their similarities.

The remainder of this document ~~reflects~~details the overall process and results of Idaho Power's *Second Amended 2019 IRP*, incorporating all modeling and input changes detailed in this Executive Summary. It is important to note that while there were multiple changes to the analysis, it resulted in only ~~two changes impacting~~one potential change to Idaho Power's Preferred Portfolio near-term 2019–2026 Action Plan~~.~~—the exit timing of Valmy Unit 2, which is explored in greater detail in Chapter 1.

~~First, Idaho Power elected to forego the option to enter into a PPA with the 100 MW Solar Franklin facility. Because this resource is no longer an option, it was removed from the modeling and the subsequent preferred portfolio. Second, the preferred portfolio in Idaho Power's filed IRP included the addition of 5 MW of demand response (DR) in 2026; in the Amended 2019 IRP, the procurement of DR shifted later in the planning period, to 2031.~~

Overall, the results of the *Second Amended 2019 IRP* ~~reflect~~continue to support a number of key components that position Idaho Power to reliably and cost-effectively serve ~~load in~~customers across the 20-year planning period. The B2H transmission line continues to be a top performing resource alternative, providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market. The *Second Amended 2019 IRP* also indicates favorable economics associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026 and exit from the remaining two units at the Jim Bridger facility by ~~the end of the 2020s. The 2019–2026 Action Plan also includes the~~year-end 2030. Additionally, the Preferred Portfolio includes 15 MW of additional demand response compared to the Preferred Portfolio identified in the *Amended 2019 IRP*. This Preferred Portfolio also supports the expanded use of renewables and energy storage, and the 2019–2026 Action Plan continues to reflect the important addition of 120 MW of solar through the construction of the Jackpot Solar Facility at year-end 2022.

Conclusion

Completion of Idaho Power's 2019 IRP has taken more than 18 months. While the company recognizes that this is an abnormal timeframe to complete a resource plan, Idaho Power is grateful for the opportunity to pause and review the company's resource planning practices in full, particularly in light of the new modeling elements. The IRP review process has helped ensure that Idaho Power's IRP efforts moving forward are more efficient, transparent, and replicable.

Further, Idaho Power appreciates the patience of the Idaho and Oregon public utility commissions, their staffs, members of the IRP Advisory Council (IRPAC~~,~~), and other stakeholders as ~~Idaho Power~~the company worked through the modeling challenges presented by its first ~~year utilizing~~time using a computer-based optimizer to construct resource portfolios. From Idaho Power's concentrated efforts on the IRP, Idaho Power ~~has learned valuable lessons throughout this process and~~ believes the resulting *Second Amended 2019 IRP* presents the least-cost, least-risk future for Idaho Power and its customers.

1. Overview

Introduction

The 2019 Integrated Resource Plan (IRP) is Idaho Power's 14th resource plan prepared in accordance with regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). 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, risk, and environmental concerns.
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 2019 IRP evaluates the 20-year planning period from 2019 through 2038. During this period, Idaho Power's load is forecasted to grow by 1.0 percent per year for average energy demand and 1.2 percent per year for peak-hour demand. Total customers are expected to increase from 550,000 in 2018 to 775,000 by 2038. Meeting this increased demand will require additional resources ~~will be needed to meet these increased demands~~.

Currently, Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. ~~Hydroelectric generation is a large part of Idaho Power's generation fleet and depends on updated streamflow projections and criteria to use in resource adequacy planning. Further discussion of Idaho Power's IRP planning criteria can be found~~The company's existing supply-side resources are further detailed in Chapter 3, while possible future supply-side resources, including storage, are explored in Chapter ~~7.~~4.

Other resources relied on for planning include demand-side management (DSM) and transmission resources~~.~~, which are further explored in Chapters 5 and 6, respectively. The goal of DSM programs is to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response 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 through the implementation and careful management of incentive programs and through outreach and education.

Idaho Power's resource planning process also includes evaluating additional 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 ~~the Northern Tier Transmission Group (NTTG). Idaho~~ 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[1] and Idaho Power retail customers.[2] The delivery of energy, both within the Idaho Power 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) and second, it is necessary in a future with high penetrations of variable energy resources (VER) and their associated intermittent production. 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 public forum is known as the IRP Advisory Council (IRPAC). The IRPAC meets most months during the development of the resource plan, and the meetings are open to the public. Members of the council include the staff of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2019 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2019 IRP, Idaho Power facilitated eight IRPAC meetings, and ~~then~~ two more for the Amended 2019 IRP. In response to stakeholder feedback for the 2019 IRP, Idaho Power implemented and maintained an online forum for stakeholders to submit requests for information and for Idaho Power to provide responses to information requests. The forum allows stakeholders to develop their understanding of the IRP process, particularly its key inputs, consequently enabling more meaningful stakeholder involvement during the process. The company makes presentation slides and other materials used at the IRPAC meetings, in addition to the question-submission forum and other IRP documents, available to the public through 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. The company has historically developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios that were quantifiably demonstrated to eliminate the identified resource deficiencies, and qualitatively varied by resource type, in which the considered resource types reflected Idaho Power's understanding that the economic performance of a resource class is dependent on future conditions in energy markets and energy policy.

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

Idaho Power received comments on the 2017 IRP encouraging the use of Capacity Expansion Modeling (CEM) for 2019 IRP portfolio development. In response, the company elected to use the AURORA model's capacity expansion modeling capability to develop portfolios for the 2019 IRP. Under this process, the alternative future scenarios are formulated first, and then the AURORA model is used to develop portfolios optimal to the selected alternative future scenarios. For example, the AURORA ~~(~~CEM~~) model~~ can be expected under an alternative future scenario ~~having~~using a high natural gas price forecast and/or high cost of carbon to ~~develop~~produce a portfolio having substantial expansion of non-carbon emitting ~~VER~~resources, such as wind and solar generation, because a portfolio is likely to be economic under such a scenario.

The use of capacity expansion modeling has resulted in a departure from Idaho Power's formerly employed practice of developing resource portfolios to specifically eliminate resource deficiencies identified by a load and resource balance. Under the capacity expansion modeling approach used for the 2019 IRP, the AURORA model selects from the 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-percent planning margin *and* regulating reserve requirements associated with balancing load~~ and~~, wind~~-~~, and solar-plant output. The model can also select to retire existing generation units, as well as build resources based on economics absent a defined capacity need. The capacity expansion modeling process is discussed in further detail in Chapter 8. ~~As will be discussed in Chapter 9, to~~

To ensure the AURORA-produced portfolios provide customers reliable and affordable energy, Idaho Power selected a subset of top-performing AURORA-produced portfolios to determine if additional resource modifications—primarily accelerated coal retirements—could further reduce costs and help achieve Idaho Power's ~~green~~clean energy commitments more quickly. Going forward, these modifications are referred to as "manual adjustments~~".~~." Modeling analysis, including in-depth discussion of manual adjustments, is examined in Chapter 9.

To meet objectives for planning margin and regulating reserve requirements, the AURORA model accounts for the capability of the existing system and selects from the pool of new supply- and demand-side resource options only when the existing system comes short of meeting ~~the~~ objectives. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand-side resources include current levels of demand response and savings from current energy efficiency programs and measures.

Idaho Power conducts a financial analysis of costs and benefits of the developed portfolios. The financial costs include construction, fuel, O&M, transmission upgrades associated with interconnecting new resource options, natural gas pipeline reservation or new natural gas pipeline infrastructure, projected wholesale market purchases, and anticipated environmental controls. The financial benefits include economic resource options, projected wholesale market sales, and the market value of renewable energy certificates (REC) for REC-eligible resources.

Idaho Power's balancing area is part of the larger western interconnection. Idaho Power must balance loads and generation per North American Electric Reliability Corporation (NERC) system reliability standards. For example, during times of acute oversupply (with no ability to sell into the market), Idaho Power must rely on available system resources to regain intra-hour balance and must sometimes curtail intermittent resources like wind and solar. Power markets are available via transmission lines to purchase or sell power inter-hour to balance the system.

An additional transmission connection to the Pacific Northwest has been part of Idaho Power's preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line. Since 2009, the addition has been called the Boardman to Hemingway (B2H) Transmission Line Project and the project has been included in the four subsequent IRPs. Idaho Power again evaluated the B2H transmission line in the 2019 IRP to ensure the transmission addition remains a prudent resource acquisition. Further discussion of the treatment of B2H in the 2019 IRP's capacity expansion modeling is provided in Chapter 8.

~~IRPs address~~While an IRP addresses Idaho Power's long-term resource needs~~.~~, near-term energy and capacity needs are planned in accordance with ~~Idaho Power's~~the company's *Energy Risk Management Policy* and *Energy Risk Management Standards*. The risk management standards were collaboratively developed in 2002 ~~between~~among Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The *Energy Risk Management Policy* and *Energy 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 *Energy Risk Management Policy* and *Energy Risk Management Standards* specify an 18-month load and resource review period, and Idaho~~ Power~~ Power's Risk Management Committee assesses the resulting operations plan monthly.

Greenhouse Gas Emissions

Idaho Power's carbon dioxide (CO_2) emission levels have historically been well below the national average for the 100-largest electric utilities in the United States (US), both in terms of CO_2 emissions intensity (pounds per megawatt-hour [MWh] generation) and total CO_2 emissions (tons) (see figures 1.1 and 1.2). The overall declining trends in terms of both CO_2 emissions intensity and total CO_2 emissions demonstrates Idaho Power's commitment to reducing ~~CO_2~~carbon emissions. The Preferred Portfolio was selected in part to further the company's pathway to reduced emissions.

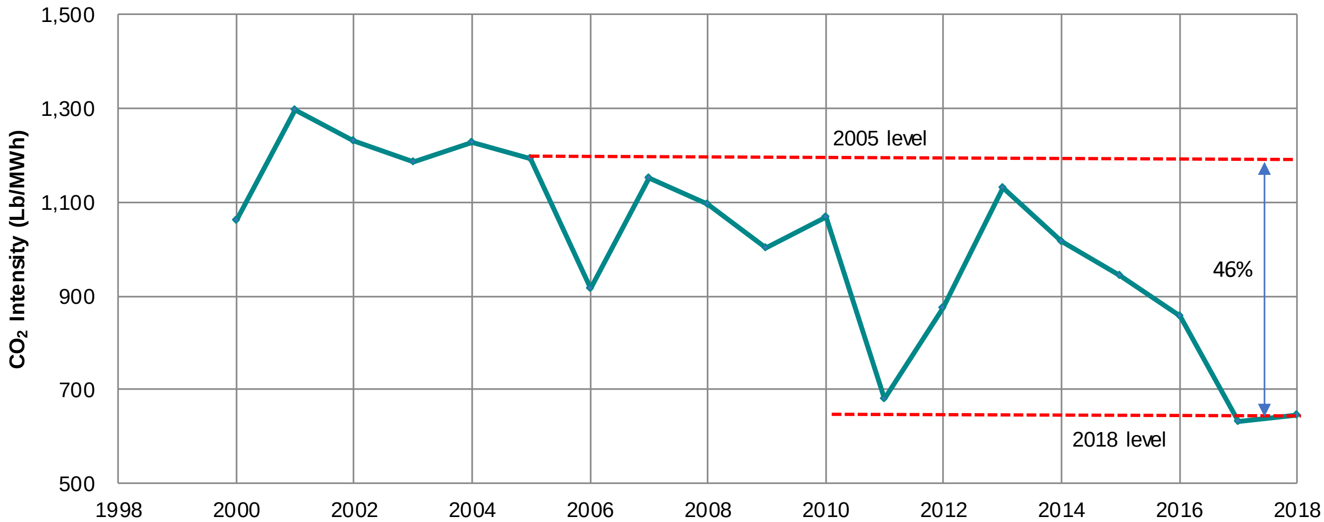

Figure 1.1 **Estimated Idaho Power CO_2 emissions intensity**

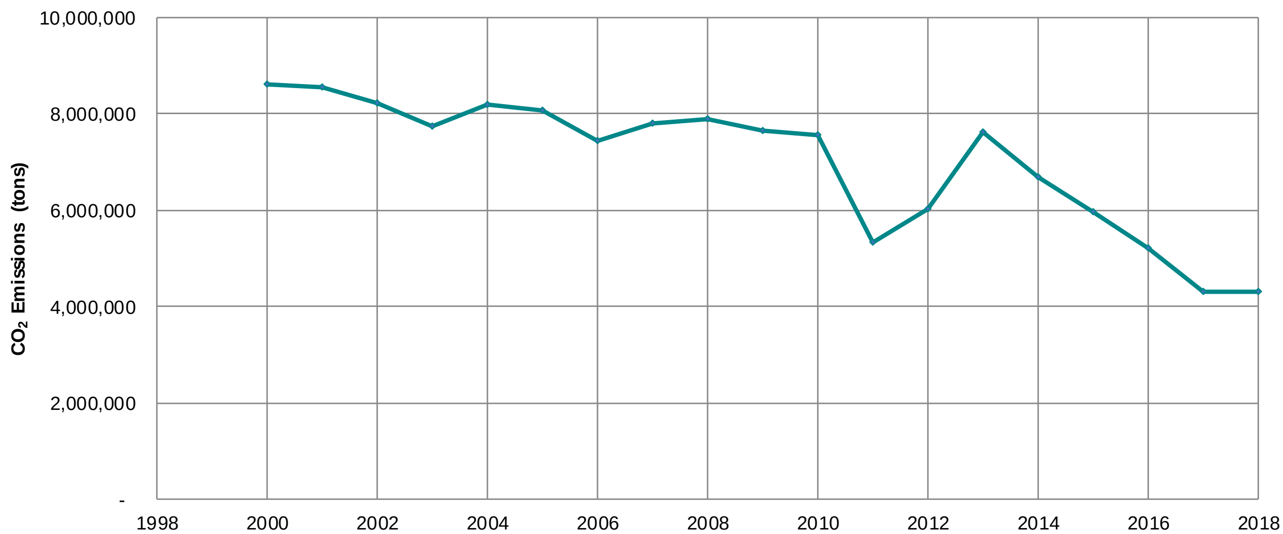

Figure 1.2 **Estimated Idaho Power CO_2 emissions**

CO_2 Emissions Reduction

Idaho Power is committed to reducing the amount of CO_2 emitted from energy-generating sources ~~emit~~. Since 2009, the company has met various voluntary goals, initiated by shareholders, to realize its commitment to CO_2 reduction. As of 2018, Idaho Power's carbon emissions intensity, expressed as pounds of CO_2 per MWh generated, has decreased by 46 percent compared to 2005 levels.

Our current goal is to ensure the average CO_2 emissions intensity of our energy sources from 2010 to 2020 is 15- to 20-percent lower than 2005 levels.

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 related to Idaho Power's CO_2 emissions, voluntarily reported annually, is also available through the Carbon Disclosure Project at cdp.net.

The portfolio analysis performed for the 2019 IRP assumes carbon emissions are subject to a per-ton cost of carbon. The ~~forecasts for~~ carbon cost forecasts are provided in Chapter 8~~ of~~, while the~~ IRP.~~ projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 9 ~~of the IRP~~.

Idaho Power Clean Energy Goal—Clean Today. Cleaner Tomorrow.™

~~Developed based on customer and stakeholder input,~~ In March 2019, Idaho Power announced a goal to provide 100 percent clean energy by 2045. This goal furthers Idaho Power's legacy of being a leader in clean energy. Key to achieving this goal of 100 percent clean energy is the company's existing backbone of nearly 50 percent hydropower generation, as well as ~~continuing~~the plan contained in the Preferred Portfolio to ~~reduce~~continue reducing carbon emissions ~~and exiting participation in its share of three~~by ending reliance on coal plants~~.~~ by year-end 2030. In addition, Idaho Power is expanding its portfolio of renewables, having reached an agreement to buy 120 megawatts (MW) of solar power from a private developer; this agreement was~~ recently~~ approved by the IPUC in December 2019.

The Preferred Portfolio identified in this *Second Amended 2019 IRP* reflects a mix of generation and transmission resources that ensures reliable, affordable energy using technologies available today. Achieving our clean-energy goal, however, will require ~~new~~ technological advances and reductions in cost~~ breakthroughs~~, as well as a continued focus on energy efficiency and demand-response programs. As it has over the past decade, the ~~advisory council~~IRPAC will continue to play a ~~key~~fundamental role in updating the IRP every two years, including analyzing new and evolving technologies ~~and continuing our~~ to help the company on its path toward a cleaner tomorrow while providing low-cost, reliable energy to our customers.

Portfolio Analysis Summary

Using the AURORA Long-Term Capacity Expansion (LTCE) model, Idaho Power produced 24 different potential resource portfolios using a combination of three natural gas price forecasts and four cost of carbon ~~emissions adders~~forecasts all under two futures~~:~~ — one with B2H and one without. The 24 portfolios include an increase in the types of resource additions and a wider range of quantities of those resources compared to the 2017 IRP. Further, the 24 portfolios ~~for~~considered in the *Second Amended 2019 IRP* include a broader range of resource types, as well as more varied amounts of nameplate generation additions:

- Wind (between 0 and 1,200 MW)
- Solar (between ~~0~~200 and 1,170 MW)
- Natural Gas Reciprocating Engines (between 0 and ~~444~~333 MW)
- Natural Gas Combined-Cycle Combustion Turbine (CCCT) (between 0 and ~~600 MW)~~

- ~~DSM (between 0 and 50 MW)~~
- ~~Battery storage (between 0 and 160 MW)~~
- ~~Nuclear (between 0 and 180 MW)~~
- ~~Biomass (between 0 and 210~~900 MW)
- Natural Gas Simple-Cycle Combustion Turbine (SCCT) (between 0 and 170 MW)
- Pumped Hydro Storage (between 0 and 500 MW)
- Nuclear (between 0 and 180 MW)
- Biomass (between 0 and 210 MW)
- Geothermal (between 0 and 30 MW)
- Demand response (between 0 and 50 MW)
- Battery storage (between 50 and 100 MW)
- Accelerated Jim Bridger Coal unit retirements (between 0 and 708 MW)
- Accelerated North Valmy Unit 2 exit (133 MW)

The diversity of resource mixes in the 24 portfolios is an important result from the ~~analysis~~LTCE. Each portfolio is built using the various natural gas and carbon scenarios within an optimized Western Electricity Coordinating Council (WECC) LTCE, illustrating the many combinations of resources that could result in a reliable system for customers at varying costs.

~~The 2019 preferred portfolio continues the trend away from using existing coal units as has been seen since the 2015 IRP, which found economic early exits from Valmy units 1 and 2. The 2017 IRP preferred portfolio included early exits from two units at Jim Bridger in 2028 and 2032. The 2019 IRP analysis has determined it is economical to exit all four coal units early at Jim Bridger.~~

The portfolios are also evaluated based on an assessment of the likelihood of the various natural gas prices, carbon prices, and B2H futures. The planning case futures represent Idaho Power's assessment of the mostly likely future forecasts of the primary known variables. ~~The portfolios are also run against additional~~Analyzing a range of possible futures also allows Idaho Power to identify the ~~costs~~cost sensitivity of various resource mixes to alternative ~~futures~~future scenarios that helps inform ~~Idaho Power's~~the company's 20-year ~~action~~ plan. Identifying and focusing on common near-term resource elements that appear in multiple futures, or identifying futures with a low likelihood, but high costs is a pragmatic way to assess resource choices.

Based on the ~~results~~outcome of the additional modeling ~~described in~~ resulting from the IRP Review (outlined in the Executive Summary and described in detail in Chapter 9~~,~~), Scenario 1 under Planning Gas-Planning Carbon and B2H conditions (Portfolio ~~16(4) and Portfolio 14(7) yield~~PGPC-B2H1) proved to be optimal in the ~~2019~~*Second Amended 2019 IRP* ~~preferred~~

~~portfolio.~~~~[3]~~. This Preferred Portfolio was derived from ~~both~~a combination of the AURORA LTCE-produced Portfolio ~~16~~13 and Portfolio 14, with additional manual adjustments to ensure the ~~portfolios~~portfolio reflected a least-cost, least-risk future specifically for Idaho Power and its customers. The manual adjustment process is discussed in more detail in Chapter 9 and the Manually Built Portfolios section in Chapter 8.

Table 1.1~~, below~~ shows the resource additions and coal exits that characterize the Preferred Portfolio over the 20-year planning period:

Table 1.1 Preferred Portfolio additions and coal exits (MW)

	Gas	Solar	Battery	Demand Response	Coal Exit
2019					-127 (Valmy)
2020					-58 (Boardman)
2021					
2022		120			-177, -133 (Bridger, Valmy*)
2023					
2024					
2025					
2026					-180 (Bridger)
2027					
2028					-174 (Bridger)
2029			~~40~~	~~30~~	
2030	~~300~~	40	30	5	-177 (Bridger)
2031	300			5	
2032			~~80~~	5	
2033			~~80~~	5	
2034		40	20	5	
2035	~~111~~	80	20	5	
2036		120	10	5	
2037	55.5		~~320~~	5	
2038	55.5	~~300~~	~~440~~	5	
Nameplate Total	**411**	**~~300~~400**	**80**	**~~30~~45**	**-~~1,026~~1026**
B2H (2026)	500				

* Idaho Power identified the potential for additional savings from a Valmy Unit 2 exit date as early as 2022. Further analysis must be conducted to determine optimal exit timing that weighs economics and system reliability, and ensures adequate capacity. Valmy Unit 2 is discussed in detail in the Valmy Unit 2 Exit Date section later in this chapter.

~~[3] Portfolio 4 was selected as the Preferred Portfolio in the original 2019 IRP filed in June 2019.~~

Comparison to Prior 2019 IRP Preferred Portfolios

The selected Preferred Portfolio of this *Second Amended 2019 IRP* is very similar to the Preferred Portfolios associated with the Amended 2019 IRP and the original 2019 IRP.

Consistent with the Amended 2019 IRP, the Preferred Portfolio of this *Second Amended 2019 IRP* continues the company's transition away from coal and shows a full exit from all coal power plants by the end of 2030. Additionally, B2H was selected in this and prior Preferred Portfolios. Additional information about Valmy and Bridger exits, as well as an update on B2H partnership discussions, can be found below.

Total battery storage and gas additions remain the same as in the Amended 2019 IRP. Additional sensitivities were conducted around gas additions to determine if reciprocating engines could serve as a more cost-effective and reliable solution. Results of the sensitivities showed optimal reciprocating engine additions in the final two years of the modeling period. While this and prior Preferred Portfolios show adoption of natural gas resources, Idaho Power views these additions as placeholders for lower-emission resources that may become cost effective in the coming years as technological advancements occur. Idaho Power will conduct a thorough modeling examination of flexible resources, as they become cost-effective, that would provide similar reliability and dispatchability as natural gas, but without the carbon footprint.

One adjustment to this Preferred Portfolio is the replacement of wind and solar resources in the outer years of the model time horizon in favor of demand response and adjusted transmission capacity. Wind adoption drops from 300 MW in the Amended 2019 to 0 MW in this Preferred Portfolio. Solar, meanwhile, drops from 1,160 MW to 400 MW in this Preferred Portfolio. While these reductions may seem like fundamental differences across Preferred Portfolios, it is important to consider Idaho Power's existing system (including a significant volume of purchased renewable energy under long-term purchase agreements), as well as other planned resources, which greatly reduce renewables' contribution to Idaho Power's peak in the late 2030s. As an example, the last 40 MW of solar added in the Amended 2019 IRP had a peak contribution of less than 3 MW. A combination of an expansion in demand response and a transmission capacity adjustment of approximately 50 MW resulted in a lower resource requirement.

The last notable difference between the *Second Amended 2019 IRP* and the Amended 2019 IRP is an additional 15 MW of demand response, which brings the total amount of expanded demand response to 45 MW.

More details about the Preferred Portfolio and resource additions and exits can be found in Chapter 10.

Action Plan (~~2019~~2020–2026)

The ~~2019 IRP~~ action plan ~~is~~for the ~~culmination of the~~*Second Amended 2019 IRP* ~~process distilled into~~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 ~~recently~~

~~announced~~ goal of 100 percent clean energy by 2045 make the 2019 action plan especially germane.

The action plan associated with the preferred portfolio is driven by its core resource actions through the mid-2020s. These core resource actions include:

- 120 MW of added solar PV capacity (2022)
- Exit from three coal-fired generating units by year-end 2022 (including Valmy 1 at year-end 2019), and from five coal-fired generating units (total) by year-end 2026
- B2H on-line in 2026

The Preferred Portfolio also is characterized by the following attributes:

- Optionality
- Flexible capacity

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 10. A chronological listing of the plan's actions follows in Table 1.2.

Table 1.2 Action Plan (~~2019~~2020–2026)

Year	Action
~~2019~~2020–2022	Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition.
~~2019~~2020-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
~~2019~~	~~Jackpot Solar PPA regulatory approval*—on-line December 2022~~
~~2019~~	~~Exit Valmy Unit 1 by December 31, 2019.*~~
~~2019~~2020–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
~~2019~~2020–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
~~2019–~~2020	Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.
2020	Exit Boardman December 31, 2020.
2020	Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.
2020	Conduct a VER Integration Study.
2020–2021	Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2.
2021–2022	Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
2022	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.

2022	Jackpot Solar 120 MW on-line December 2022.
~~2023–2026~~	~~Procure or construct resources resulting from RFP (if needed).~~
~~2025~~2022	Exit Valmy Unit 2 by December 31, ~~2025.~~2022.*
2026	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H).

~~* These items~~Jackpot Solar PPA and the Valmy Unit 1 exit were complete at the time the *Second Amended 2019 IRP* was filed on October 2, 2020.

* Further analysis will be conducted to evaluate the optimal exit date of Valmy Unit 2, weighing exit economics and system reliability concerns. Further discussion of Valmy Unit 2 is provided below.

Given the complexities and ongoing-developments related to Valmy Unit 2, Bridger units, and B2H, an update on each is provided below.

Valmy Unit 2 Exit Date

The IRP provides a robust method of assessing future resource options over a two-decade timeframe. Although AURORA modeling has consistently showed an economic exit of Valmy Unit 2 in 2025 in WECC-optimized runs, cost analyses specific to Idaho Power suggest the potential for additional savings from earlier exit dates. Exiting Valmy Unit 2 in 2022, rather than 2025, would provide approximately $3 million in NPV savings due to avoided capital investment and net O&M reductions.

However, potential savings based on a long-term analysis should not be the sole consideration. Rather, near-term economic and reliability impacts of an earlier exit must also be evaluated using data points such as forward market hub price forecasts, planned unit outages, Idaho Power's customer risk management processes, and recent market conditions, among other items. The objective of this near-term analysis would be to identify any tradeoffs between an earlier exit date and the ability to provide reliable, affordable power.

For these reasons, in the months ahead Idaho Power will conduct further analysis of Valmy Unit 2 exit timing. In particular, the company will assess the feasibility of a 2022 exit, which would require 15 months of advance notice to the plant operator (i.e. a decision prior to September 30, 2021). The analysis will consider customer reliability, more current operating budgets and economics to inform a decision that will minimize costs for customers while ensuring Idaho Power can maintain system reliability.

As noted in the 2017 IRP, Idaho Power will also need to explore whether a long-term firm purchase of transmission and energy in the South can adequately replace any deficit caused by an earlier Valmy Unit 2 closure. Idaho Power may need to ensure availability by issuing a request for proposal for a long-term purchase. Absent such long-term purchase, it may not be feasible to exit the unit prior to the completion of B2H.

Bridger Unit Exit Dates

Idaho Power identified early Bridger unit exits in 2022, 2026, 2028, and 2030. The 2022 and 2026 exits will be Bridger Unit 1 and Bridger Unit 2, with the exit order to be determined. The 2028 and 2030 exits will be Bridger Unit 3 and Bridger Unit 4, with the order also to be determined.

Idaho Power owns one-third of each Bridger unit, and PacifiCorp owns two-thirds of each Bridger unit and is the Bridger plant operator. In its 2019 IRP, PacifiCorp identified different exit dates for each Bridger unit, with the first unit being exited in 2023, one year after Idaho Power's identified first unit exit date. Idaho Power and PacifiCorp have not developed contractual terms that would be necessary to allow for the potential earlier exit of a Bridger unit by one party, and not both parties. Any new contractual terms may impact the costs and assumptions built into Idaho Power's resource planning, and therefore the specific timing of exits identified in this IRP.

Boardman to Hemingway Participant Update

The B2H permitting project's co-participants are Idaho Power, BPA, and PacifiCorp. To date, the co-participants' contemplated ownership interests in B2H have generally corresponded with their capacity needs, and with the current allocation of permitting costs borne by each co-participant as follows: Idaho Power: 21 percent, BPA: 24 percent, and PacifiCorp: 55 percent. However, the B2H co-participants are exploring an alternative asset, service, and ownership arrangement under which Idaho Power would assume BPA's contemplated 24 percent ownership share in B2H, and Idaho Power would provide BPA and/or its customers with transmission wheeling service across southern Idaho. As part of the terms of the contemplated transmission service agreement, BPA and/or its customers would pay for transmission wheeling under the provisions of Idaho Power's Open Access Transmission Tariff (OATT). Under this arrangement, BPA and/or its customers' OATT payments would, over time, ensure recovery of Idaho Power's revenue requirement associated with BPA's respective usage of B2H.

Importantly, the contemplated arrangement will have an immaterial impact on Idaho Power's analysis of B2H in this *Second Amended IRP*. While Idaho Power's formal ownership interest and share of the cost of B2H would increase, the company's original 21 percent ownership share would continue to reflect the company's approximate share of the costs for B2H used to serve Idaho Power's retail customers. The company's assumption of BPA's contemplated 24 percent ownership would be offset by the transmission wheeling service to BPA and/or its customers. Thus, Idaho Power's share of the financial responsibility for B2H, as analyzed in this *Second Amended IRP*, would remain unchanged. As a result, the *Second Amended IRP*'s use of a 21 percent ownership share for purposes of the IRP's least-cost, least risk analysis is still appropriate.

Moreover, the contemplated arrangement would provide a number of benefits to Idaho Power's customers that they would not realize under the original approach, including:

- Ownership will be consolidated, simplifying design, construction, and operations. This will reduce project costs. In particular, each owner has certain design standards. A consolidation simplifies coordination and construction activities.
- Without a federal owner, local property taxes will increase and provide additional value to the communities along the line-route.

If Idaho Power determines that its customers will experience additional economic or other benefits by virtue of owning 45 percent of B2H, the company will evaluate these net benefits in future resource planning exercises.

As of the filing of this *Second Amended IRP*, regular discussions among the co-participants are ongoing; however, no definitive agreements have been reached. The reason for the extended time for deliberation is the complexity of the arrangement as it pertains to potential asset swaps, legacy contracts, and extensive transmission planning studies. Idaho Power continues to believe that B2H is the best path for its customers and looks forward to sharing additional specific terms of arrangements with the parties as soon as possible. Idaho Power's 21 percent share, as modeled in this *Second Amended IRP*, remains the best and most up-to-date information for use in the IRP process.

2. Political, Regulatory, and Operational Issues

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor's Office of Energy and Mineral Resources (OEMR), 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 2019, the ISEA prepared the *2019 Idaho Energy Landscape Report*. The 2019 report is a resource to help Idahoans better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.

The *2019 Idaho Energy Landscape Report* concludes the health of Idaho's economy and quality of life depend on access to affordable and reliable energy resources. 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 2019 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 4.7 percent annually from 1997 to 2017, yet Idaho's energy consumption (transportation, heat, light, and power) grew just 1.1 percent annually from 1990 to 2016.

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. Based on Idaho’s 2016 electricity energy sources, approximately 32 percent was comprised of market purchases and energy imports from out-of-state generating resources owned by Idaho utilities.

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 2017 data, hydroelectricity and coal are the two largest sources of Idaho’s electricity, comprising 53 and 17 percent, respectively. Natural gas makes up 14 percent, and non-hydro renewables, principally wind power, solar, geothermal, and biomass, account for approximately 14 percent. Idaho’s electricity rates were the fifth lowest among the 50 states in 2017.

State of Oregon 2018 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 inaugural 2018 biennial report provides foundational energy data about Oregon and examines the existing policy landscape while identifying several 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 2017 energy supply consisted primarily of hydroelectric power, coal, and natural gas, renewable energy continues to make up an increasing share of the energy mix each year. Wind energy consumed in Oregon increased 741 percent between 2004 and 2016, and solar generation increased from 28 MWh in 2008 to 266,000 MWh in 2016. 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 variable renewable resources, like wind and solar, into the grid has increased from 12.1 percent in 2012 to 18.4 percent in 2016.

The main theme of the 2018 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.

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 68 percent of Idaho Power's hydroelectric generating capacity and 32 percent 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 VER, further enabling the achievement of Idaho Power's clean energy goals.

The 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, subject to appeal, on May 24, 2019. 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 estimates will occur no earlier than 2022. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, IPUC staff, and a third-party intervenor recognizing a total of $216.5 million in expenditures had been reasonably incurred through year-end 2015, and therefore, should be eligible for inclusion in customer rates at a later date. The IPUC approved the settlement in April 2018 (IPUC Order No. 34031).

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.

Relicensing activities include the following:

1. Coordinating the relicensing process
2. Consulting with regulatory agencies, tribes, and interested parties on resource and legal matters
3. Preparing and conducting studies on fish, wildlife, recreation, archaeological resources, historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
4. Analyzing data and reporting study results
5. 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 2019 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 ongoing 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. 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. 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.

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power 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 program in the Snake River Basin. The company 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 (CAMP) 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 provided the framework for modeling future management activities on the ESPA. These management activities were included in the modeling to develop the flow file for assessing 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 study was completed in 2018. As suggested by feedback from the 2017 IRP, as well as the results of Idaho Power's *2018 Variable Energy Resource Integration Analysis* (2018 VER Study), several improvements were incorporated into AURORA and the resource portfolio analysis of the 2019 IRP to model the adequate maintenance of reserve margins as resources are added or removed in the IRP portfolios.

In compliance with Order Nos. 17-075 and 17-223 in Oregon Docket No. UM 1793, Idaho Power filed the 2018 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 2018 VER Study (which were developed in collaboration with the study's technical review committee, including personnel from both the Idaho and Oregon PUCs) yielded estimated regulating reserve requirements necessary to balance the netted system of load, wind, and solar (net load). The 2018 VER Study expressed these regulating reserve requirements as the dynamically varying function of several factors:

- Season (spring, summer, fall, winter)
- Load-base schedule (two-hour ahead schedule)
- Time of day (for load)
- Wind-base schedule
- Solar-base schedule

The regulating reserve requirements necessary to balance net load for a given hour can be expressed as dependent on the above five factors. The derivation of the regulating reserve requirements from a net-load perspective captures the tendency of the three elements (i.e., load, wind, and solar) to deviate from their respective base schedules in an offsetting manner.

Therefore, the amount of regulating reserve required for net load is less than the sum of the individual requirements for each element.

The 2018 VER Study suggested a unified VER integration analysis may be a favored approach for assessing impacts and costs for incremental wind and solar additions going forward. The 2018 VER Study also notes that Idaho Power's system is nearing a point where the current system of reserve-providing resources (i.e., dispatchable thermal and hydro resources) can no longer integrate additional VERs without taking additional action to address potential reserve requirement shortfalls. The 2018 VER Study concluded that additional investigation is warranted into the combined effect of wind and solar, in a unified VER integration cost analysis, along with the effects of Energy Imbalance Market (EIM) participation.

The 2018 VER Study also identified that, based on the current resources on Idaho Power's system, 173 MW of additional VERs could be integrated before reserve margin violations exceed 10 percent of the operating hours during the year. The study also concluded that at the high relative penetration levels of variable wind and solar that currently exist on Idaho Power's system, additional analysis is warranted, and as Idaho Power gains more experience operating as part of the EIM.

AURORA modeling used in the 2019 IRP has improved since the 2018 VER Study. The 2019 IRP uses the AURORA model Version 13.2.1001, which incorporates improvements in modeling reserve requirements combined with Idaho Power's own modeling improvements and assumptions. Specifically, the HCC hydro units can use the hydro logic in AURORA, which allows for spill. The resources dedicated to maintaining the additional reserves incur costs, such as spill, which are captured within the model as increased cost to the portfolio. The model version enhancements allow Idaho Power to include all 12 HCC hydro units as providing reserves in the 2019 IRP LTCE process, which mirrors a more realistic HCC hydro operation. The existing thermal units' ability to provide reserves is nearly identical to the previous setup~~.~~, except that Valmy does not provide reserves. The evolution of using the enhanced capabilities in AURORA to define the resource portfolios using the LTCE logic while simultaneously incorporating the VER dynamic reserve rules associated with varying quantities of VERs is a significant advancement in portfolio design at Idaho Power.

For the 2019 IRP, integration charges for VERs are not used as an input into the AURORA model because portfolio development for the 2019 IRP is being performed through LTCE modeling. Under this approach, the model's selection of resources is driven by the objective to construct portfolios that are low cost and achieve the planning margin and regulating reserve requirements. Based on approximations of the 2018 VER Study's dynamically defined regulating reserve requirements, the 2019 IRP includes hourly regulating reserves associated with current levels of load, wind, and solar, as well as future portfolios having higher levels of load and potentially higher levels of VERs.

For the 2019 IRP analysis, the 2018 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. Improvements in Version 13 of the

AURORA model, compared to when the study was performed,[4] allow the 2018 VER Study reserve rules to dynamically establish hourly reserves for different quantities of variable resources in a portfolio. The reserves are defined separately, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2019 IRP include defining hourly reserve requirements for "Load Up," "Load Down," "Solar Up," "Solar Down," and "Wind Up." The "Wind Down" reserves are included in the "Load Down" reserves, as AURORA cannot dynamically apply the "Wind Down" reserves rules as defined and applied in the study.

The 2019 IRP analysis is a step toward a unified VER integration cost analysis as concluded in the 2018 VER Study. While the 2018 VER study provided valuable information regarding the rules for reserve requirements, the modeling performed for the 2019 IRP provides more information on how VERs affect Idaho Power's system and the ability to maintain sufficient reserves. The 2019 IRP has allowed Idaho Power, via the AURORA model, to quantitatively capture and enforce the hourly flexibility requirements for a portfolio to dynamically change regulating reserves in line with the 2018 VER Study reserve requirement rules.

The results of the 2019 IRP portfolio development show that additional VERs are selected in a majority of LTCE portfolios, and many of the portfolios show new solar resources selected and coal units being retired. This indicates the model has sufficient regulating reserves to economically retire a reserve-contributing coal unit while adding new solar resources.

Additionally, Idaho Power's load is forecast to grow through 2022 and 2023, which allows more VERs to be successfully integrated. The additional VERs in the AURORA integrated portfolio analysis dynamically increase the system reserves associated with increased VER energy by applying the 2018 VER Study rules to model reliable system operations. However, when additional incremental VERs are added to the system outside, or between, IRP cycles, there is still a need to identify the incremental cost of maintaining adequate reserves for reliable operations. This will require Idaho Power to continue to build on the advancements made by the 2019 IRP analysis of a unified VER integration cost first identified in the 2018 VER Study. As noted in the near-term action plan, this will be performed in conjunction with the additional experience the company gains from continued operation in the EIM, as well as with the collaboration of a Technical Review Committee as part of an updated integration study.

Community Solar Pilot Program

Idaho

In response to customer interest, in June 2016, Idaho Power filed an application with the IPUC requesting an order authorizing Idaho Power to implement an optional Community Solar Pilot Program.

For the pilot program, Idaho Power proposed to build and own a 500-kilowatt (kW) single-axis tracking community solar array in southeast Boise and allow a limited number of Idaho Power's Idaho customers to voluntarily subscribe to the generation output on a first-come basis.

[4] The 2018 VER Study was performed using Version 12.1.1046 of the AURORA model.

Participating customers would be required to pay a one-time, upfront subscription fee, and in return would receive a monthly bill credit for their designated share of the energy produced from the array. Because the Idaho Power's 2015 IRP did not reflect a load-serving need for the proposed solar resource, the overall program design was intended to result in program participants covering the full cost of the project with nominal impact to nonparticipating customers.

The IPUC approved the pilot program on October 31, 2016, and marketing efforts for customer subscriptions began immediately.

Due to insufficient program enrollment, in February 2019, Idaho Power filed with the IPUC to suspend Schedule 63, Community Solar Pilot Program. The IPUC opened Case No. IPC-E-19-05 to process the request, and on April 26, 2019, issued Order No. 34317 approving the company's request to suspend Schedule 63. Idaho Power will continue to work with stakeholders to determine a community solar program design that could be successful in a future offering.

Oregon

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 CSP 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 filing, Idaho Power has completed the interconnection study process for a 2.95 MW project that intends to participate in the community solar program. The company believes that the project is well positioned to obtain the necessary certifications to participate in the community solar program. The proposed 2.95 MW project will use all but 305 kW of Idaho Power's initial capacity allocation.

Renewable Energy Certificates

A REC, also known as a green tag, ~~represent~~represents the green or renewable attributes of energy produced by a certified renewable ~~resources~~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. Retired RECs also enable the retiring entity to claim the renewable energy attributes of the corresponding amount of energy delivered to customers.

A certifying tracking 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.

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, each dollar of green power purchased represents 100 kilowatt-hours (kWh) of renewable energy delivered to the regional power grid, providing the Green Power Program participant associated claims for the renewable energy. Most of the participant funds are used to purchase RECs from renewable projects in the Northwest and to support Solar 4R Schools, a program designed to educate students about renewable energy by placing solar installations on school property. A portion of the funds are used to market the program, with the prospect of increasing participation in the program. On behalf of program participants, Idaho Power obtains and retires RECs.

In 2018, Idaho Power purchased and subsequently retired 18,148 RECs on behalf of Green Power participants. In 2018, all Green Power RECs were sourced from projects located in Idaho.

Renewable Portfolio Standard

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established an 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 percent of Oregon's total retail electric sales. In 2017, per U.S. Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.4 percent of Oregon's total retail electric sales. As a smaller utility in the state of Oregon, Idaho Power will likely have to meet a 5-percent RPS requirement beginning in 2025.

In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25 percent by 2025 to 50 percent renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change.

The State of Idaho does not currently have an RPS.

Carbon Adder/Clean Power Plan

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

The final rule provided states until September 2018 to submit implementation plans, phasing in several compliance periods beginning in 2022 and achieving the final emissions goals by 2030. In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP under Section 111(d) of the CAA for existing electric utility generating units.

The new proposed rule is limited to reduction and compliance measures occurring at the physical location of each plant, removing the proposal to require reductions outside the boundaries of plants. The Affordable Clean Energy (ACE) rule also provides for more state-specific control over implementation of the rule to address GHG emissions from existing coal-fired power plants, with a focus on state evaluation of improvement potential, technical feasibility, applicability, and remaining useful life of each unit.

Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, and due to the existing and potential changes in legislation, regulation, and government policy with respect to environmental matters as a result of the presidential administration's executive orders and the EPA's proposal to repeal and replace the CPP, as of the date of this report and in light of these executive actions, Idaho Power is uncertain whether and to what extent the replacement CPP may impact its operations in the near future. For the 2019 IRP, Idaho Power assumes a carbon adder to account for costs associated with CO_2 emissions. The analyzed carbon cost forecasts are discussed in Chapter 8.

3. Idaho Power Today

Customer Load and Growth

Residential construction growth in southern Idaho.

In 1994, Idaho Power served approximately 329,000 general business customers. ~~Today~~In 2019, Idaho Power ~~serves~~served more than 560,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,245 MW in 1994 to about 3,400 MW. On July 7, 2017, the peak-hour load reached 3,422 MW—the system peak-hour record.

Average firm load increased from 1,375 average MW (aMW) in 1994 to 1,801 aMW in 2018 (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 3.1 and Table 3.1. The data in Table 3.1 suggests each new customer adds over 5.0 kW to the peak-hour load and over 3.0 average kW (akW) to the average load.

Since 1994, Idaho Power's total nameplate generation has increased from 2,661 MW to 3,594 MW. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1994. Additionally, Idaho Power has added about 228,000 new customers since 1994.

Idaho Power anticipates adding approximately 10,900 customers each year throughout the 20-year planning period. The expected-case load forecast for the entire system predicts summer peak-hour load requirements will grow nearly 50 MW per year, and the average-energy requirement is forecast to grow over 20 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

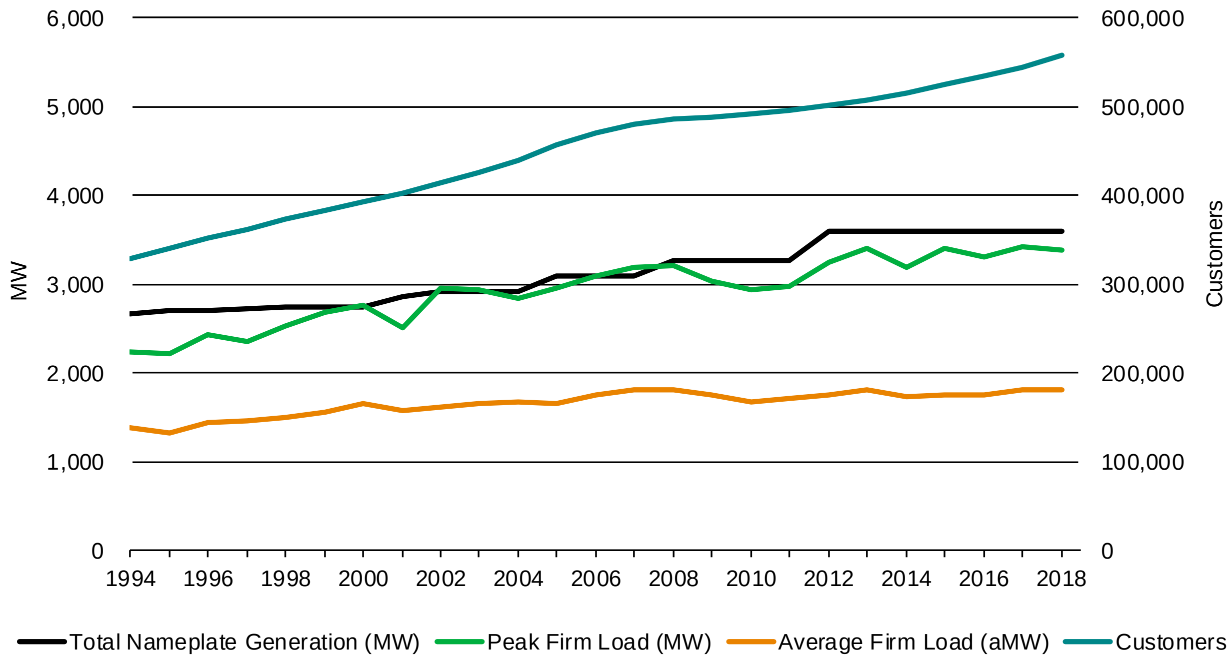

Figure 3.1 **Historical capacity, load, and customer data**

Table 3.1 **Historical capacity, load and customer data**

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1994	2,661	2,245	1,375	329,094
1995	2,703	2,224	1,324	339,450
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

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
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
2017	3,594	3,422	1,807	544,378
2018	3,659[2]	3,392	1,810	556,926

1 Year-end residential, commercial, and industrial customers, plus the maximum number of active irrigation customers.
2 Reported nameplate capacity reflects recent modifications to hydroelectric facilities.

2018 Energy Sources

Idaho Power's energy sources for 2018 are shown in Figure 3.2. Idaho Power-owned generating capacity was the source for 71.4 percent of the energy delivered to customers. Hydroelectric production from company-owned projects was the largest single source of energy at 46.4 percent of the total. Coal contributed 17.5 percent, and natural gas- and diesel-fired generation contributed 7.5 percent. Purchased power comprised 28.6 percent of the total energy delivered to customers. Of the purchased power, 9.3 percent of the total delivered energy was from the wholesale electric market. The remaining purchased power, 19.3 percent, was from long-term energy contracts (*Public Utility Regulatory Policies Act of 1978* [PURPA] and PPAs) 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 energy delivered to customers.

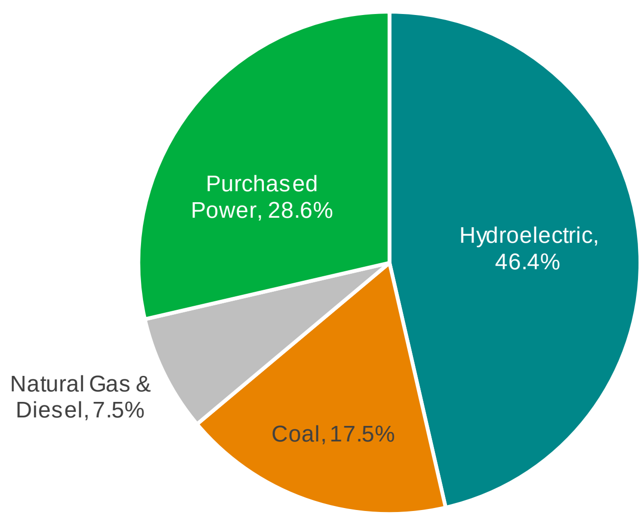

Figure 3.2 2018 energy sources

Existing Supply-Side Resources

Table 3.2 shows all of Idaho Power's existing company-owned resources, nameplate capacities, and general locations.

Table 3.2 Existing resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	652.6	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	11.5	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	6.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
North Valmy*	Coal	283.5	North Central Nevada
Langley Gulch	Natural Gas—CCCT	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT	172.8	Southwest Idaho
Danskin	Natural Gas—SCCT	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,658.6**	

* North Valmy Unit 1 was exited at the end of 2019.

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 annual generation equal to approximately 1,000 aMW, or 8.7 million MWh, under median water conditions.

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 percent of Idaho Power's annual hydroelectric generation and enough energy to meet over 30 percent 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 are the Fall Chinook Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

Brownlee Reservoir is the main HCC reservoir and Idaho Power's only reservoir with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately 1 million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1 percent 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 received from the US Army Corps of Engineers (COE) as outlined 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 US 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.

Brownlee Reservoir's releases are managed to maintain operationally stable flows below Hells Canyon Dam in the fall because of the Fall Chinook Program adopted by Idaho Power in 1991. 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 plan 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, and C. J. Strike projects. These three projects are operated within the FERC license requirements to coincide with daily system peak demand when load-following capacity is available.

Idaho Power completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail, a threatened species under the ESA. The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to relicense the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power annually alternated operating the Bliss and Lower Salmon facilities under ROR and load-following operations. Study results indicated while load-following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A *Bliss Rapids Snail Protection Plan* developed in consultation with the FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company has been able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has received a license amendment from FERC for both projects that allows load-following operations to resume.

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 water bank 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.

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 generators

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.[5] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 22 percent annually, with an annual average of 11.3 percent. Idaho Power estimates cloud seeding provides an additional 424,000 acre-feet in the upper Snake River, 113,000 acre-feet in the Wood River Basin, 229,000 acre-feet in the Boise Basin, and 212,000 acre-feet from the Payette River Basin. At program build-out (including additional aircraft and remote ground generators), Idaho Power estimates additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,269,000 acre-feet. The additional water from cloud seeding fuels the hydropower system along the Snake River.

Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment (SNOWIE) was a joint project between 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

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

Footnotes continued on the next page.

after seeding has taken place. Ground breaking discoveries continue to be evaluated from this dataset collected in winter 2017. Multiple scientific publications have already been published,[6] with more planned for submission about the effects and benefits of cloud seeding.

For the 2018 to 2019 winter season, Idaho Power continued to collaborate with the State of Idaho and water users to augment water supplies with cloud seeding. The program included 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 included 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. The 2018 to 2019 season provided abundant storms and seeding opportunities. Suspension criteria were met in some areas in early February, and operations were suspended for the season for all target areas by early March.

Coal Facilities

~~Jim Bridger~~

~~Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired 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. For the 2019 IRP, Idaho Power used the AURORA model's capacity expansion capability to evaluate a range of exit dates for the company's participation in the Jim Bridger units, where the evaluated exit dates were determined by the model within feasibility guidelines.~~

~~North Valmy~~

~~Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. NV Energy has 50 percent ownership and is the operator of the North Valmy facility. For the AURORA-based capacity expansion modeling performed for the 2019 IRP, Idaho Power assumes an exit from Unit 1 participation at year-end 2019 and from Unit 2 participation no later than year-end 2025. Pre-2025 exit from Unit 2 was an option selectable by the AURORA model; however, the model did not select pre-2025 exit for any portfolios.~~

Boardman

Idaho Power owns 10 percent, or 64.2 MW (generator nameplate rating), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. Portland General Electric has 90 percent ownership and is the operator of the Boardman facility.

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[6] 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.

The 2019 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. An agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the EPA related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NOx) emissions, requires the Boardman facility to cease coal-fired operations by year-end 2020.

Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired 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. For the 2019 IRP, Idaho Power used the AURORA model's capacity expansion capability to evaluate a range of exit dates for the company's participation in the Jim Bridger units, where the evaluated exit dates were determined by the model within feasibility guidelines.

North Valmy

Idaho Power currently owns 50 percent, or 284 MW (generator nameplate rating), of the second generating unit at the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consisted of two generating units. NV Energy has 50 percent ownership and is the operator of the North Valmy facility. For the AURORA-based capacity expansion modeling performed for the 2019 IRP analysis, Idaho Power captured the exit from Unit 1 participation at year-end 2019 and assumed an exit from Unit 2 participation no later than year-end 2025 and no earlier than year-end 2022. The exit from Unit 1 occurred as planned at year-end 2019. Precise exit timing of Valmy Unit 2 will be examined by Idaho Power in the coming months to determine an optimized exit strategy that considers economics of the exit and the requirement for the provision of affordable, reliable power. See Chapter 1 Summary, section Valmy Unit 2 Exit Date for further discussion of Valmy Unit 2.

Natural Gas Facilities and Salmon Diesel

~~Langley Gulch~~

~~Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens 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.~~

~~Danskin~~

~~The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse W251B12A combustion turbines at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. Idaho Power is currently evaluating options to repower the two smaller Danskin turbines to improve efficiency and start capability, expand dispatch flexibility, and lower emissions. The Danskin units are dispatched when needed to support system load.~~

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173-MW Siemens–Westinghouse 501F natural gas-fired Simple-Cycle Combustion Turbine (SCCT) located east of the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant is also dispatched as needed to support system load.

Danskin

The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse W251B12A SCCTs at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. Idaho Power is currently evaluating options to repower the two smaller Danskin turbines to improve efficiency and start capability, expand dispatch flexibility, and lower emissions. The Danskin units are dispatched when needed to support system load.

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant which utilizes a nominal 318-MW natural gas-fired Combined-Cycle Combustion Turbine (CCCT). The plant consists of one 187-MW Siemens 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.

Salmon 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

In 1994, a 25-kW solar PV array with 90 panels was installed on the rooftop of Idaho Power's corporate headquarters (CHQ) in Boise, Idaho. The 25-kW solar array is still operational, and Idaho Power uses the hourly generation data from the solar array for resource planning.

In 2015, Idaho Power installed a 50-kW solar array at its new Twin Falls Operations Center. The array came on-line in October 2016.

Idaho Power also has solar lights in its parking lot and uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring streamflows, and operating cloud-seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program and owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events.

Solar End-of-Feeder Project

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

The Solar End-of-Feeder Pilot Project is a small-scale (18 kW_{AC}) 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. 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 Project was installed and has been in operation since October 2016. The project has operated as expected ~~through the first two years of operation~~ by effectively mitigating low voltage. The Solar End-of-Feeder Pilot Project ~~is considered complete and~~ will continue to be monitored internally ~~in the following years~~.

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 out to the company's grid. Most customers use solar PV systems. As of March 31, 2019, there were 3,595 solar PV systems interconnected through the company's customer generation tariffs with a total capacity of 30.356 MW. At that time, the company had received completed applications for an additional 436 solar PV systems, representing an incremental capacity of 7.213 MW. For further details regarding customer-owned generation resources interconnected through the company's on-site generation and net metering services, see tables 3.3 and 3.4.

Table 3.3 Customer generation service customer count as of March 31, 2019

Resource Type	Active	Pending	Total
Idaho Total	3,589	429	4,018
Solar PV	3,541	428	3,969
Wind	38	0	38
Other/hydroelectric	10	1	11
Oregon Total	55	8	63
Solar PV	54	8	62
Wind	1	0	1
Other/hydroelectric	0	0	0
Total	**3,644**	**437**	**4,081**

Table 3.4 Customer generation service generation capacity (MW) as of March 31, 2019

Resource Type	Active	Pending	Total
Idaho Total	29.533	7.125	36.658
Solar PV	29.189	7.113	36.302
Wind	0.198	0.000	0.198
Other/hydroelectric	0.146	0.012	0.158
Oregon Total	1.170	0.100	1.270
Solar PV	1.167	0.100	1.267
Wind	0.002	0.000	0.002
Other/hydroelectric	0.000	0.000	0.000
Total	**30.703**	**7.225**	**37.928**

Oregon Solar Program

In 2009, the Oregon Legislature passed Oregon Revised Statute (ORS) 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 US 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. Cogeneration and small power producers (CSPP) ~~is~~are often associated with PURPA. Individual states were tasked with establishing PPA terms and conditions, including price, 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 which, 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 Schedule 73, and for Oregon QFs, Schedule 85. QFs also have the option to sell energy "as-available" under Schedule 86.

As of April 1, 2019, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,148 MW of nameplate capacity. These PURPA contracts are for hydroelectric projects, cogeneration projects, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power generation facilities. Of the 133 contracts, 127 were on-line as of April 1, 2019, with a cumulative nameplate rating of approximately 1,119 MW. Figure 3.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

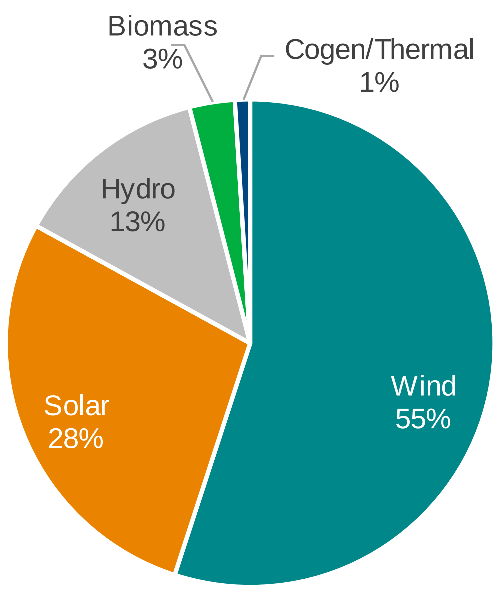


Figure 3.3 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. 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 2019 IRP was completed in October 2018. Detail on signed PURPA contracts, including capacity and contractual delivery dates, is included in *Appendix C—Technical Appendix*.

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, LLC, 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 percent of all RECs generated by the project for the remaining term of the agreement. Idaho Power's contract with Raft River Energy I, LLC, expires April 2033.

Neal Hot Springs

In May 2010, the IPUC approved a PPA with USG Oregon, LLC, for approximately 22 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, LLC expires 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 located north of the Idaho–Nevada state line near Rogerson, Idaho. Under the terms of the PPA, Idaho Power will receive all RECs from the project. Jackpot Solar is scheduled to be on-line December 2022.

An application was submitted to the IPUC on April 4, 2019, requesting an order that approves 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 860-089-100(3) and (4), of an exception from Oregon's competitive-bidding requirements for electric utilities as the PPA with Jackpot Holdings, LLC presents a time-limited opportunity to acquire a resource of unique value to Idaho Power customers. On December 24, 2019, the IPUC issued Order No. 34515 approving the PPA with Jackpot Holdings, LLC.

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (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. Idaho Power holds one more option to extend through 2025, exercisable in 2020. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Wholesale Contracts

Idaho Power currently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts).

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 6. 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 6.1 in Chapter 6).

4. Future Supply-Side Generation and Storage Resources

Generation Resources

Supply-side generation resources include traditional generation resources, renewable resources, and storage resources. Idaho Power gives equal treatment to both supply-side and demand-side resources. As discussed in Chapter 5, 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 2019 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 2019 IRP is the 2018 Annual Technology Baseline (ATB) report released by the National Renewable Energy Laboratory (NREL) in July 2018.[7] 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 7. All cost information presented are in nominal dollars with an on-line date of 2023 for all levelized cost of energy (LCOE) calculations. Provided levelized cost figures are based on Idaho Power's cost of capital and may differ from other reported levelized costs.

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 as related to its fleet of hydroelectric generators. In the 2019 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.

Solar

The primary types of solar generation technology are utility-scale photovoltaic (PV) and distributed PV. In general, PV technology absorbs solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material creates an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy passes through an inverter, converting it to alternating current (AC) that can then be used on site or sent to the grid.

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

[7] atb.nrel.gov/

the solar-power potential for an area. NREL insolation charts show the desert southwest has the highest solar potential in the continental US.

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

~~The capital-cost estimate used in the 2019 IRP for utility-scale PV resources is $1,334 per kW[8] for PV with a single-axis tracking system. The 30-year LCOE for PV with single-axis tracking is $67 per MWh assuming a 26-percent annual capacity factor.~~

~~Rooftop solar was considered in two forms as part of the 2019 IRP. The capital-cost estimate used for residential rooftop solar PV resources is $2,947 per kW for PV. The 25-year LCOE for residential rooftop solar PV resources is $180 per MWh assuming a 21-percent annual capacity factor. The capital-cost estimate used for commercial and industrial rooftop solar PV resources is $2,160 per kW. The 25-year LCOE for commercial and industrial rooftop solar PV resources is $133 per MWh assuming a 21-percent annual capacity factor. Rooftop solar is assumed to be fixed tilt and south facing.~~

For Idaho Power's cost estimates and operating parameters for utility-scale PV resources, see the Supply-Side Resource section of *Appendix C: Technical Report* of the *Second Amended 2019 IRP*.

Rooftop solar was considered in two forms as part of the 2019 IRP.

In addition to generic locations for solar PV arrays, the 2019 IRP analyzed select areas that are reflective of a targeted siting for solar capacity within Idaho Power's service area. Targeted solar is a process of identifying select locations on the delivery system where a solar facility could defer growth or reliability investments on the distribution or transmission system. These select areas are limited in size at 0.5 MW, with a total of 10 MW for the 20-year planning period. ~~The capital-cost estimate used in the 2019 IRP for a targeted siting for grid benefit PV resource is $1,734 per kW. The 30-year LCOE is $77 per MWh assuming a 26-percent annual capacity factor.~~ See the Targeted Grid Solar section later in this chapter for further discussion.

Advancements in energy storage technologies have focused on coupling storage devices with solar PV resources to mitigate and offset the effects of an intermittent generation source. This coupling or pairing of resources was modeled and considered in the 2019 IRP. For a more complete description of battery storage, ~~please~~ refer to the Storage Resources section of this chapter.

~~The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 10 MW (40 MWh) lithium ion (Li) battery is $1,575 per kW. The LCOE is $90 per MWh assuming a 22-percent annual capacity factor for the entire facility.~~

[8] ~~Capital costs for solar PV expressed in terms of dollars per AC kW, assume DC:AC ratio of 1.3:1.~~

~~The levelized cost of energy assumes a 30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.~~

~~The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 20 MW (80 MWh) Li battery is $1,735 per kW. The LCOE is $120 per MWh assuming an 18-percent annual capacity factor for the entire facility. The LCOE assumes a 30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.~~

~~The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 30 MW (120 MWh) Li battery is $1,849 per kW. The LCOE is $152 per MWh assuming a 15-percent annual capacity factor for the entire facility. The LCOE assumes a 30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.~~

For Idaho Power's cost estimates and operating parameters for single-axis tracking, utility-scale PV resources, see the Supply-Side Resource section of *Appendix C: Technical Report* of the *Second Amended 2019 IRP*.

Solar-Capacity Value

For the 2019 IRP, Idaho Power updated the capacity value of solar using the 8,760-based method developed by NREL[9] and detailed herein. The NREL method is specifically described as a technique for representing VER capacity value in capacity expansion modeling, such as conducted using the AURORA model for the 2019 IRP. The capacity value of solar PV generation is a measurement of the contribution of solar PV capacity to meet system demand (including planning reserves). The capacity value of the solar PV is expressed as the percentage of nameplate AC capacity that contributes to the top peak net-load hours.

Capacity Value for Solar PV Methodology

The methodology employed by Idaho Power to calculate the capacity value for solar PV uses an Idaho Power system load-duration curve (LDC) and a net load-duration curve (NLDC), representing the net of system load and solar PV generation, for an entire year. The LDC reflects the total system load, sorted by hour, from the highest load to the lowest load. The NLDC represents the total system load minus the time-synchronized contribution from solar PV generation. The resulting net load is then sorted by hour, from the highest load to the lowest load.

As shown in Figure 4.1, the capacity value of existing solar PV generation is the difference in the areas between the LDC (System Load) and NLDC (Net Load) during the top 100 hours of the duration curves divided by the rated AC capacity of the solar PV generation installed. These 100 hours can be a proxy for the hours with the highest risk for loss of load.

$$\cancel{Capacity\ Value\ (\%) = \frac{\sum_1^{100} LDC - \sum_1^{100} NLDC}{Solar\ PV_{rated}}}$$

[9] nrel.gov/docs/fy17osti/68869.pdf

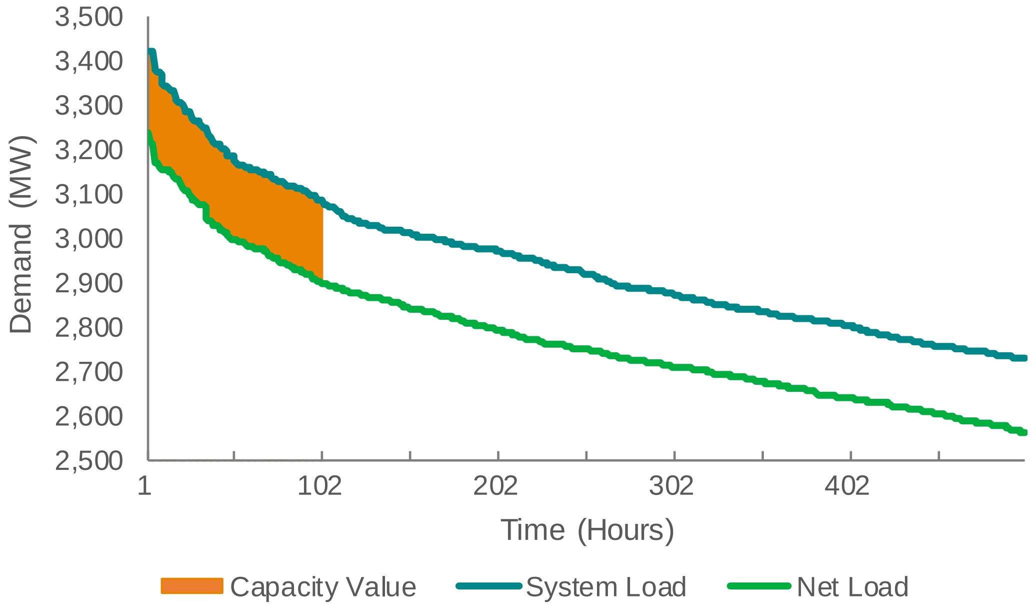


Figure 4.1 Capacity value of solar PV

In a similar fashion, the capacity value of the next solar PV plant, or the marginal capacity value (δ) of incremental solar PV, can be calculated using the same methodology. The marginal NLDC (δ) of incremental solar PV is calculated by subtracting the time-synchronized generation of incremental solar capacity from the NLDC. The resulting time series is again sorted by hour, from the highest load to the lowest load.

As shown in Figure 4.2, the marginal capacity value of incremental solar PV is the difference in the areas between the NLDC (net load) and the NLDC (δ) (Net load [δ]) divided by the rated AC incremental solar PV capacity.

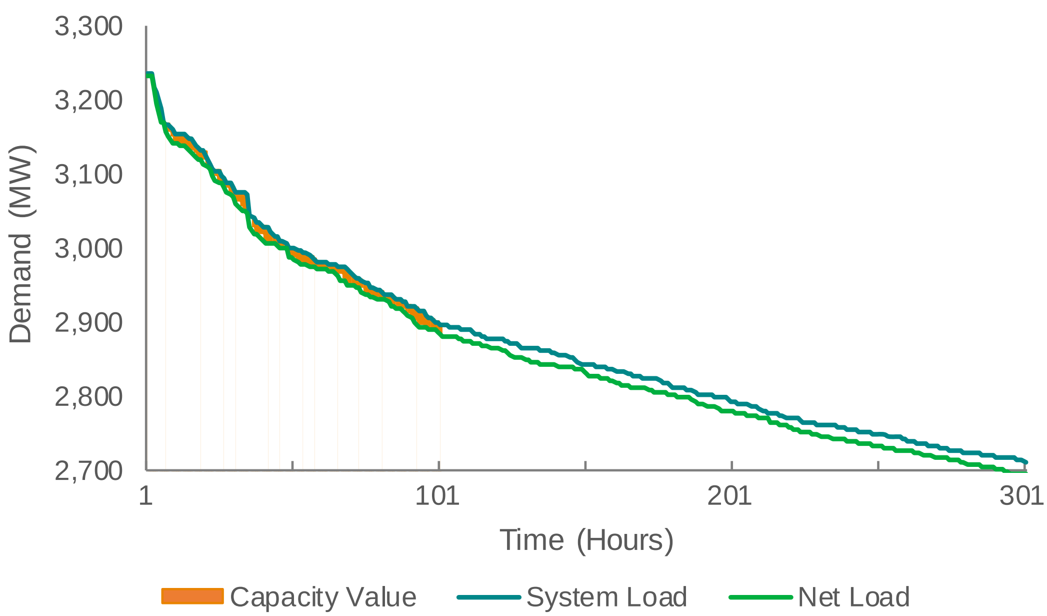


Figure 4.2 Marginal capacity value

Results

Capacity value was derived for three categories: 1) existing operational solar PV, 2) solar PV projects in construction, and 3) the future PV projects capacity value. The marginal capacity value of future PV projects was calculated in 40 MW alternating current (MWAC) increments.

The capacity value of the existing operational solar PV was first calculated by applying the method to the 2017 system load. The capacity value was also calculated using 2018 system load. The final capacity value was obtained by averaging the capacity value obtained for both years.

Table 4.1 shows the capacity value for the solar PV presently connected and for the solar PV projects in construction. The existing operational solar PV was evaluated as a single solar PV generator with 289.5 MWAC, representing the sum of the rated capacity of the existing operational solar PV generation on Idaho Power's systems as of June 2019.

The capacity value of the projects under construction was calculated as a single solar PV generator with a rated capacity of 26.5 MWAC, representing the rated capacity of the sum of the solar PV generation projects under construction.

Table 4.1 Summary of capacity value results

	Capacity Value (% of Nameplate Capacity)
Existing operational solar PV (289.5 MW)	61.86%
Projects under construction (26.5 MW)	47.92%

Idaho Power calculated the marginal capacity value of incremental solar PV projects each with a capacity rating of 40 MWAC. As the overall system peak load is decreased by the addition of incremental amounts of solar PV, eventually the top 100 hours of peak load contain fewer and fewer hours when solar PV may contribute to reducing the peak load. Therefore, the incremental capacity value of solar decreases as more solar is added to the system. Figure 4.3 shows the resulting capacity value for every 40 MWAC increment of solar PV.

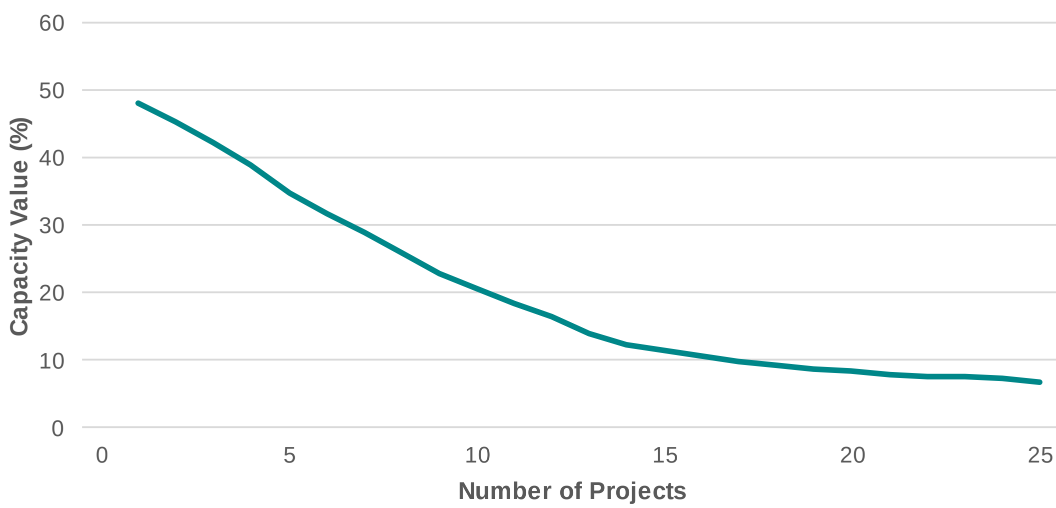


Figure 4.3 Capacity value of incremental solar PV projects (40 MW each)

Targeted Grid Solar

Idaho Power analyzed transmission and distribution (T&D) deferral benefits associated with targeted solar. 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. 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.
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. **Methodology**: If the net forecast (electrical demand minus an assumed solar generation 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 solar. The selection was made to represent different areas, solar project sizes, and deferral periods, as well as the frequency at which projects are likely to be deferrable on Idaho Power's system. The solar generation required to achieve each deferral and the value of each deferral varied.

Table 4.2 Solar capacity required to defer infrastructure investments

Location	Years Deferred	Deferral Savings	Solar Project Size (kW)	Capacity Value ($/kW)
Blackfoot	8	$79,550	964	$82.52
Siphon (Pocatello)	4	$107,789	4,472	$24.10
Wye (Boise)	3	$19,767	2,339	$8.45
Nampa	2	$66,516	1,516	$43.87
Dietrich	2	$16,965	229	$74.08

The average capacity value of the identified investments was $46.60 per kW. This value was used for the T&D deferral locational value and reflected in Targeted Solar.

It is anticipated that a locational value of T&D deferral may apply to an annual average of 500 kW of solar over the 20-year IRP forecast for a total potential of 10 MW of solar. This resource option was added to the AURORA LTCE model.

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 300º Fahrenheit (F) 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 ~~used~~ for binary-cycle geothermal generation~~ in~~, see the ~~2019 IRP assume a capital-cost~~Supply-Side Resource section of ~~$6,495 per kW, and~~*Appendix C–Technical Appendix* of the ~~25-year LCOE is $144 per MWh based on an 88-percent annual capacity factor~~*Second Amended 2019 IRP*.

Hydroelectric

Hydroelectric power is the foundation of Idaho Power's electrical generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. The development of new, large hydroelectric projects is unlikely due to a lack of adequate sites and hurdles associated with regulatory, environmental, and permitting challenges that accompany new, large hydroelectric facilities. However, small-scale hydroelectric projects have been extensively developed in southern Idaho on irrigation canals and other sites; many of which have PPA contracts with Idaho Power.

Small Hydroelectric

Small hydroelectric projects, such as ROR and projects requiring limited or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects. The potential for new, small hydroelectric projects was studied by the ISEA's Hydropower Task Force, and the results released in May 2009 indicate between 150 to 800 MW of new hydroelectric resources could be developed in Idaho. The reported figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. ~~The capital-cost estimate used in the 2019 IRP for small hydroelectric resources is a range from $4,000 per kW to $8,400 per kW, and an associated 75-year economic life.~~

For Idaho Power's cost estimates and operating parameters for small hydroelectric resources, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 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 ranging in size from 1 to 3 MW each. Most potential wind sites in southern Idaho lie between the south-central and the southeastern part of the state. Productive wind energy sites are in areas that receive consistent, sustained winds greater than 15 miles per hour and are the best candidates for wind 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 unique operational challenges for electric utilities and system operators due to the intermittent and 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 peak-hour capacity. For the 2019 IRP, Idaho Power applied a capacity factor of 5 percent for peak-hour planning. The 2019 IRP assumed an annual average capacity factor of 35 percent for projects sited in Idaho and 45 percent for projects sited in Wyoming. ~~The capital-cost estimate used in the 2019 IRP for wind resources is $1,722 per kW, regardless of geographic location. The 25-year LCOE is $114 per MWh for projects located in Idaho and $94 per MWh for projects located in Wyoming.~~

For Idaho Power's cost estimates and operating parameters for wind resources, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 IRP*.

Biomass

The 2019 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 2019 IRP considers anaerobic digesters as a best fit for biomass resources within the service area.

~~The capital-cost estimate used in the 2019 IRP for an anaerobic digester project is $3,902 per kW for a 35-MW facility. The anaerobic digester is expected to have an annual capacity factor of 85 percent. Based on the annual capacity factors, the 30-year LCOE is $101 per MWh for the anaerobic digester.~~

For Idaho Power's cost estimates and operating parameters for an anerobic digester, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 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 to the ability to integrate renewable energy into the grid. Conventional thermal generation technologies include natural gas-fired resources, nuclear, and coal.

Natural gas resources are identified in many modeled portfolios, but Idaho Power considers these resources proxies for future resources that can meet system needs and help accomplish the company's clean energy goals while imposing the least cost on customers. The company is looking for ways to meet or offset its future dispatchable resource needs in accordance with its 2045 goals but acknowledges advances in technology and cost reductions may be required.

Natural Gas-Fired Resources

Natural gas fired resources burn natural gas in a combustion turbine to generate electricity. CCCTs are commonly used for baseload energy, while less-efficient SCCTs are used to generate electricity during peak-load periods. 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 percent (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 a HRSG.

Multiple CCCT plants, like Idaho Power's Langley Gulch project, are planned in the region due to a sustained depression in natural gas prices, the demand for baseload energy, and additional operating reserves necessary to integrate intermittent resources. While there is not currently a scarcity of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. ~~The capital-cost estimate used in the 2019 IRP for a CCCT resource is $1,182 per kW, and the 30-year LCOE at a 60-percent annual capacity factor is $71 per MWh.~~

For Idaho Power's cost estimates and operating parameters for a CCCT resource, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 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 variable and intermittent resources.

Several natural gas-fired SCCTs have been brought on-line in the region in the past two decades, primarily in response to the regional energy crisis of 2000–2001. High electricity prices combined with persistent drought conditions during 2000–2001, 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.

~~The 2019 IRP evaluated a 170-MW industrial-frame (F class) SCCT unit. The capital-cost estimate used in the 2019 IRP is $1,009 per kW. The industrial-frame unit is expected to have an annual capacity factor of 5 percent.~~

~~Based on an annual capacity factor of 5 percent, the 35-year LCOE is $386 per MWh for the industrial-frame SCCT unit. If Idaho Power were to identify the need, it would evaluate the two types of SCCT technologies in greater detail prior to issuing an RFP to determine which technology would provide the greatest benefit.~~

For Idaho Power's cost estimates and operating parameters for a SCCT unit, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 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. 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 before 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 in the sense 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 the 2019 IRP, Idaho Power modeled RICE facilities of 55 MW and 111.1 MW nameplate capacity. The capital-cost estimate used for a reciprocating engine resource of 55 MW is $1,077 per kW. The 55 MW facility has a corresponding 40-year LCOE, assuming a 15-percent annual capacity factor, of $164 per MWh. Larger facilities can benefit from various economies~~

~~of scale. The capital-cost estimate used for a RICE resource of 111.1 MW is $959 per kW. The 111.1 MW facility has a corresponding 40-year LCOE, assuming a 15-percent annual capacity factor, of $155 per MWh.~~

For Idaho Power's cost estimates and operating parameters for RICE facilities, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 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 utilizing 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 that higher overall efficiencies 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 addition, reduced costs for the steam host provide a competitive advantage that would ultimately help the local economy.

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 2019, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company.

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 the wake of the 2011 earthquake and tsunami in Japan relating to the Fukushima nuclear plant, global concerns persist over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to estimate the full impact this disaster will have on the future of nuclear power generation in the US. Idaho Power continues to monitor the advancement of SMR technology and will continue to evaluate it in the future as the Nuclear Regulatory Commission reviews proposed SMR designs in the coming years.

For the 2019 IRP, a 60-MW small-modular plant was analyzed. Grid services provided by the SMR include baseload energy, peaking capacity, and flexible capacity. ~~The capital-cost estimate used in the IRP for an advanced SMR nuclear resource is $4,683 per kW, and the 40-year LCOE, evaluated at an annual capacity factor of 90 percent, is $121 per MWh.~~

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 Appendix* of the *Second Amended 2019 IRP*.

Coal Resources

Conventional coal-fired generation resources have been a 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 any new conventional coal generation resources.

Integrated Gasification Combined Cycle (IGCC) is an evolving coal-based technology designed to substantially reduce CO_2 emissions. As the regulation of CO_2 emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow CO_2 to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or "syngas" that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

The addition of CO_2-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. CO_2 has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of CO_2 produced would require the development of underground sequestration methods. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. No new coal-based energy resources were modeled as part of the 2019 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-Columbia 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 intermittent renewable resources like wind and solar 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 2019 IRP considered a variety of energy-storage technologies and modeled battery storage and pumped hydro storage.

Battery Storage

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery-storage technologies at various stages of development. Commonly studied technologies include vanadium redox-flow battery (VRB), Lithium-Ion (Li) battery systems and Zinc battery systems.

Advantages of the VRB technology include its low cost, long life, and easy scalability to utility/grid applications. Most battery technologies are not a good fit for utility-scale applications because they cannot be easily or economically scaled to much larger sizes. The VRB overcomes much of this issue because the capacity of the battery can be increased just by increasing the size of the tanks that contain the electrolytes, which also helps keep the cost relatively low. VRB technology also has an advantage in maintenance and replacement costs, as only certain components need replaced about every 10 years, whereas other battery technologies require a complete replacement of the battery and more frequently depending on use. Idaho Power recognizes the continued technological development of VRB and will continue to monitor price trends and utility scalability of this technology in the coming years.

In recent years Li battery systems have been installed commercially in the US. Li battery storage systems realize high charging and discharging efficiencies. Li-based energy storage devices present potential safety concerns due to overheating. Costs for Li battery systems are still relatively high. Idaho Power recognizes the continued technological development of Li batteries used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and scalability of this technology in the coming years.

~~For the 2019 IRP, Idaho Power modeled Li battery technology in two arrangements. The first arrangement assumes 5 MW capacity with 20 MWh (4 hours) of energy. The capital-cost estimate for Li battery storage is $1,813 per kW. The 10-year LCOE, evaluated at an annual capacity factor of 11 percent, is $232 per MWh[10].~~

~~The second Li battery-storage arrangement modeled in the 2019 IRP analysis has a capital-cost estimate of $2,947 per kW. The 10-year LCOE, evaluated at an annual capacity factor of 23 percent, is $250 per MWh. This arrangement assumes 5 MW capacity with 40 MWh (8 hours) of energy.~~

For Idaho Power's cost estimates and operating parameters for Li battery technology, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 IRP*.

~~[10] The levelized energy costs for energy storage are driven overwhelmingly by fixed costs, particularly capital costs. Consequently, levelized costing for energy storage technologies in this chapter does not include the cost of recharge energy. While not insignificant, recharge energy costs are expectedly relatively small given the utilization of energy storage to recharge during acute periods of grid energy abundance.~~

Pumped-Storage Hydro

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 energy in the form of water, pumped 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.

For pumped storage to be economical, there must be a significant differential (arbitrage) in the value of electricity between peak and off-peak times to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Typical round-trip cycle efficiencies are between 75 and 82 percent. The efficiency of a pumped hydro-storage facility is dependent on system configuration and site-specific characteristics. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient enough to make pumped storage an economically viable resource. Due to the recent increase in the number of wind and solar projects on the regional grid, the amount of intermittent generation provided, and the ancillary services required, Idaho Power will continue to monitor the viability of pumped hydro storage projects in the region. ~~The capital-cost estimate used in the 2019 IRP for pumped hydro storage is $1,964 per kW, and the 75-year LCOE is $175 per MWh.~~

For Idaho Power's cost estimates and operating parameters for pumped hydro storage, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *Second Amended 2019 IRP*.

5. DEMAND-SIDE RESOURCES

Demand-Side Management Program Overview

DSM resources offset future energy loads by reducing energy demand through either efficient equipment upgrades (energy efficiency) or peak-system demand reduction (demand response). DSM resources have been a leading resource in IRPs since 2004, providing average cumulative system load reductions of over 240 aMW by year-end 2018. Historically, ~~DSM~~ energy efficiency potential resources have first been forecasted, screened for cost-effectiveness, and then all available ~~DSM~~energy efficiency potential resources are included into the IRP before considering new supply-side resources. In the 2019 IRP, based on input from the IRPAC, two alternative approaches to estimate energy efficiency potential were tested and considered.

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

Included in the preferred portfolio is ~~440~~45 MW of peak summer capacity reduction from demand response and 234 aMW of average annual load reduction from energy efficiency. Additionally, energy efficiency will reduce peak by 367 MW.

Energy Efficiency Forecasting—Potential Assessment

While Idaho Power tested alternative energy efficiency potential forecasting methods in the 2019 IRP, the underlying initial potential study was the same as the 2017 IRP methodology and served as a base case for comparison purposes. For the 2019 IRP, Idaho Power's third-party contractor (contractor), provided a 20-year forecast of Idaho Power's energy efficiency potential from a total resource cost (TRC) perspective. The contractor also provided additional forecasts based on different economic scenarios.

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 potential study, the contractor applies the TRC test for cost-effectiveness, which compares lifetime energy and capacity benefits to the incremental

cost of the measure. 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.

Alternative ~~DSM~~Energy Efficiency Modeling Methods

Idaho Power tested two alternate ~~DSM~~energy efficiency modeling approaches in the 2019 IRP. In addition to the baseline potential study which assessed technical, economic, and achievable potential in a manner consistent with past IRPs, the company tested a sensitivity modeling method and a technically achievable potential supply curve bundling technique.

Sensitivity Modeling

The first alternative energy efficiency potential assessment method tested was a sensitivity modeling analysis. Under this approach, the contractor created three levels of achievable energy efficiency potential based on three different alternate cost forecasts. Each forecast corresponded to different natural gas price forecasts. The goal was to create differing levels of cost-effective energy efficiency based on the three sets of alternate costs that would be further analyzed in the AURORA portfolio selection process. Based on input from the IRPAC, the sensitivity approach was not adopted in the final IRP modeling because the method was observed to inappropriately screen energy efficiency potential at multiple steps in the process.

Technically Achievable Supply Curve Bundling

Based on input from IRPAC, a second approach was tested that established bundles of technically achievable energy efficiency potential. Technically achievable 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.

The contractor created 10 technical achievable bundles of energy efficiency potential based on increasing efficiency costs and bundled by percentile. These technical achievable potential bundles were based on net levelized TRC across the 20-year planning period (0–10th percentile, 10th–20th percentile, etc.). An 11th bundle captured extremely high-cost measures above $250 per MWh. The bundles of energy efficiency measures or technologies were created across customer class and building types. For example, one cost bundle could contain residential, commercial, industrial, and irrigation measures if the underlying measures had similar costs. Table 5.1 lists the cumulative bundle resource potential in aMW over 20 years and the weighted average net levelized TRC over the same period.

Table 5.1 Technical achievable bundles size and average cost

	5-Year Potential (aMW)					
Bundle	2019	2023	2028	2033	2038	20 Year Net Average Real Cost ($/MWh)
0–10th Percentile	1	7	17	27	33	-$102
10–20th Percentile	3	8	17	27	33	-$18
20–30th Percentile	3	12	22	29	34	$14
30–40th Percentile	1	8	18	27	33	$32
40–50th Percentile	2	8	16	25	34	$38
50–60th Percentile	1	7	14	22	33	$48
60–70th Percentile	2	11	21	28	33	$69
70–80th Percentile	3	16	27	32	34	$131
80–90th Percentile	2	13	26	31	34	$133
90–100th Percentile	2	11	24	30	33	$189
High Cost	2	14	27	35	41	$2,235

Idaho Power ~~makes every effort~~strives to ensure all cost-effective energy efficiency potential is fully accounted for in resource planning. Because Idaho Power's load forecast includes a level of cost-effective energy efficiency expected to occur during a given forecast period, an important step in this process was to compare the level of future cost-effective energy efficiency included in the 2019 IRP load forecast to bundled levels of efficiency represented in Table 5.1. This comparison concluded the amount of energy efficiency included in the first seven bundles of energy efficiency potential was approximately equal to the amount of efficiency potential included in the load forecast and the economic-achievable potential identified in the initial potential assessment. Thus, energy efficiency bundles for the zero through the 70th percentile are considered reflected in all IRP resource portfolios. The higher cost bundles, 8 through 11, were available to be selected by the AURORA model in the LTCE process but were shown to not be economically competitive against other resources.

The 0 to 10th and 10 to 20th percentile bundles' average TRCs are negative because the non-energy impacts exceed the cost. Figure 5.~~2~~1 shows cumulative technical achievable energy efficiency potential beginning in 2019. The energy efficiency bundles from 0 to 70th percentile bundle are representative of the levels of energy efficiency included in 2019 IRP portfolios. Higher-cost bundles beyond the 60 to 70th percentile bundle were determined not to be economically competitive when compared with other resources. Table 5.1 shows that bundles beyond the 60 to 70th percentile bundle have weighted average measure costs of $131 per MWh or greater.

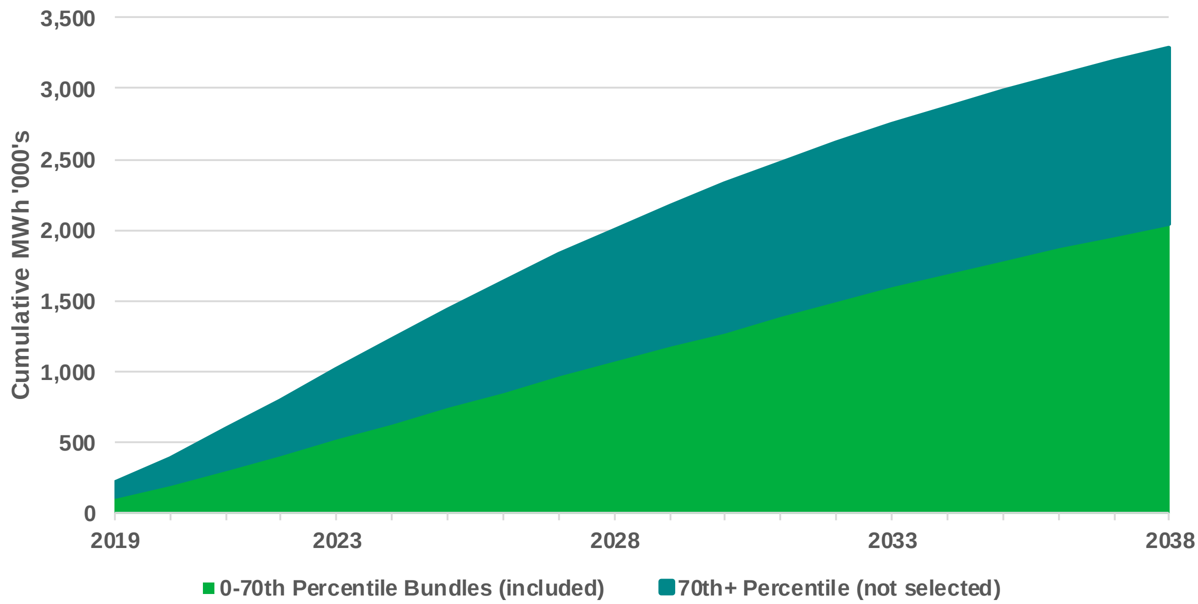


Figure 5.1 Energy-efficient bundles selected by the IRP model and bundles that were not economically competitive and were not selected for the 2019 IRP portfolios

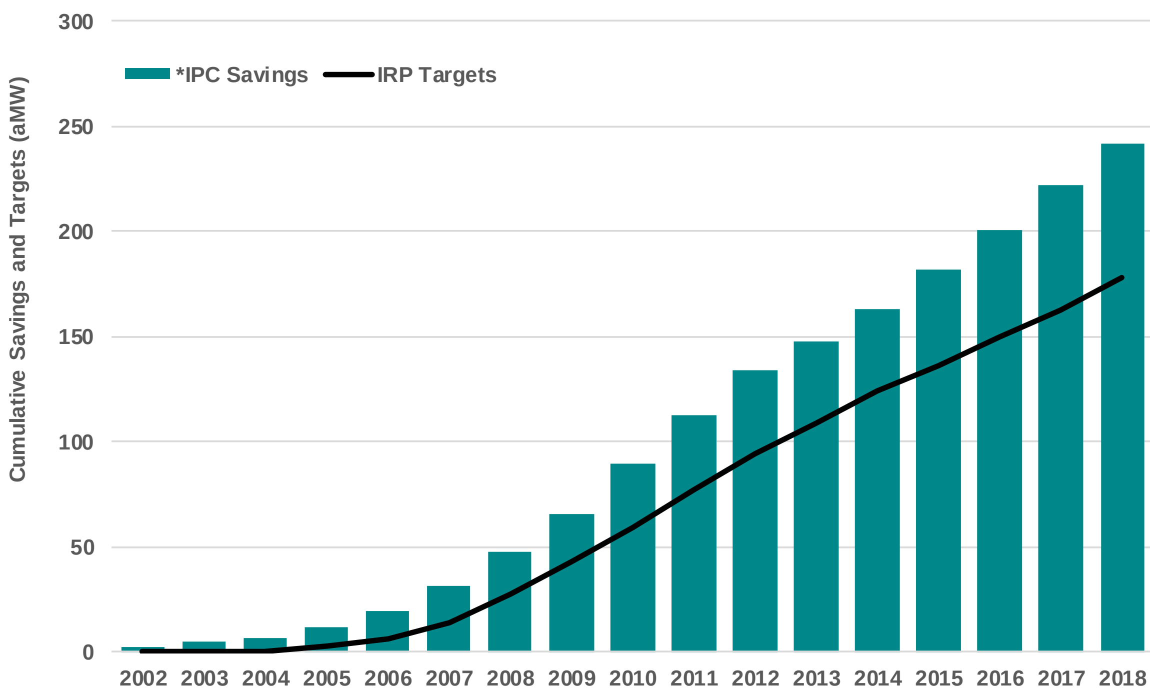
Future Energy Efficiency Potential

The 20-year energy efficiency potential included in the 2019 IRP declined from 273 aMW in 2017 IRP to 234 aMW in the 2019 IRP. System on-peak potential from energy efficiency also declined from 483 MW to 367 MW from the 2017 IRP to the 2019 IRP. Most of the decline in energy efficiency potential was due to the reduction of the number of residential lighting measures that will be available for Idaho Power energy efficiency programs. The *2007 Energy Independence and Security Act* manufacturing standard that will take effect in 2020 will increase efficiency standards for residential lighting. It is assumed this standard will only allow LED bulbs to meet manufacturing standards for most light bulbs that consumers purchase. Although the reduction from energy efficiency potential available for Idaho Power's programs will be reduced, the energy savings will still reduce overall load without utility intervention. A detailed discussion about the impacts on programs from codes and standards changes is available in the *2018 Energy Efficiency Potential Study*.

DSM Program Performance and Reliability

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 242 aMW, or over 2 million MWh, of reduced supply-side energy production to customers through 2018. Figure 5.~~3~~2 shows the cumulative annual growth in energy efficiency effects over the 17-year period from 2002 through 2018, along with the associated IRP targets developed as part of the IRP process since 2004.



* ~~IPC~~Idaho Power savings include Northwest Energy Efficiency Alliance (NEEA) non-code/federal standards savings

Figure 5.2 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 5.2 shows the 2018 year-end program results, expenses, and corresponding benefit-cost ratios.

Table 5.2 Total energy efficiency portfolio cost-effectiveness summary, 2018 program performance

Customer Class	2018 Savings (MWh)	TRC ($000s)	Total Benefits ($000s) (20-Year NPV*)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	43,651	$13,634	$43,310	3.2	2.7
Industrial/commercial	95,759	$37,567	$70,324	1.9	3.2
Irrigation	19,001	$11,948	$36,344	3.0	7.6
Total	**158,411**	**$63,149**	**$149,978**	**2.4**	**3.4**

* NPV=Net Present Value

Note: Excludes market transformation program savings.

Energy Efficiency Reliability

The company contracts 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 (IPMVP), the Database for Energy Efficiency Resources, and the Regional Technical Forum's (RTF) evaluation protocols.

Timing of impact evaluations are 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 2017 and 2018 ranged between 84 and 101 percent. The savings weighted realized savings average over the same period is 100 percent.

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three programs. Table 5.3 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 2018 summer season, Irrigation Peak Rewards participants contributed 82 percent of the total potential demand-reduction capacity, or 313 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2018 Annual Report*.

Table 5.3 2018 Demand response program capacity

Program	Customer Class	Reduction Technology	2018 Total Demand Response Capacity (MW)	Percent of Total 2018 Capacity*
A/C Cool Credit	Residential	Central A/C	37	10%
Flex Peak Program	Commercial, industrial	Various	33	9%
Irrigation Peak Rewards	Irrigation	Pumps	313	82%
Total			**383**	**100%**

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

Figure 5.~~4~~3 shows the historical annual demand response program capacity between 2004 and 2018. 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.

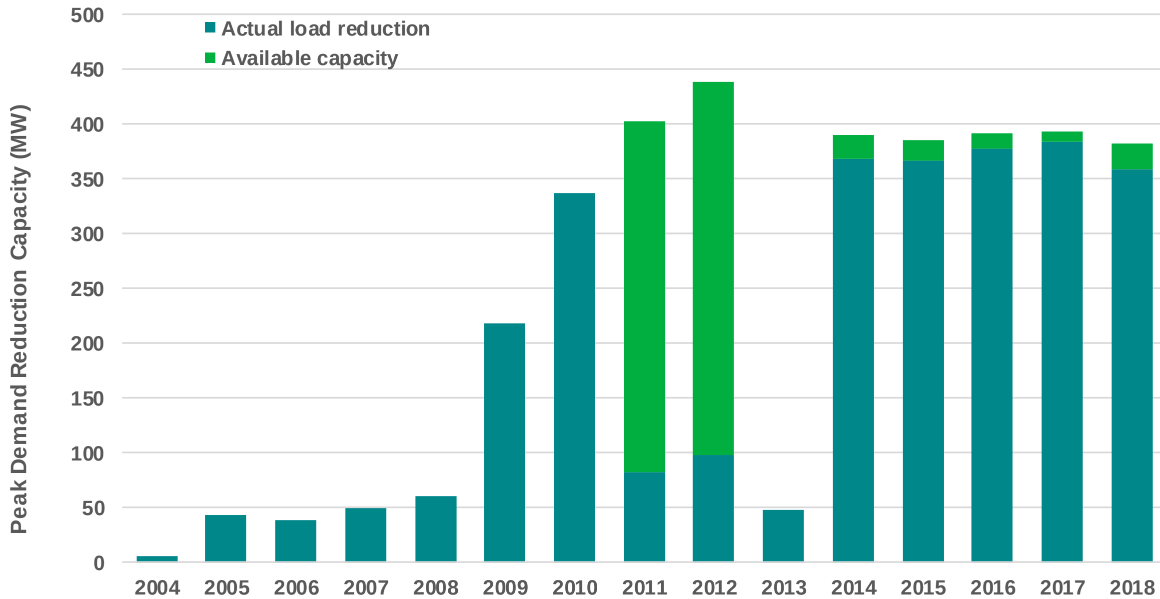


Figure 5.3 Historic annual demand response program performance

Demand Response Resource Potential

Under the current program design and participation levels, demand response from all programs is committed to provide 390 MW of peak capacity during June and July throughout the IRP planning period, with reduced amount of program potential available during August. The committed demand response included in the IRP has a capacity cost of $29 per kW-year.

As part of the IRP's rigorous examination of the potential for expanded demand response, the company first evaluated additional demand-response capacity need outside of the AURORA model to determine any constraints needed in the modeling process. The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 ~~MWs~~MW blocks of incremental new demand response each year for selection in AURORA starting in 2023~~.~~ at a cost of $60 per kW-year. This additional demand response, beyond the 390 ~~MWs~~MW the company considers a committed resource, was ~~used~~selected in various amounts by the AURORA LTCE model in ~~23~~22 of the 24 potential portfolios ~~for~~and was nearly maximized with a total of ~~420~~45 MW ~~available~~ in the Preferred Portfolio. ~~This expanded DR will require additional customer participation and was modeled in AURORA at a cost of $60 per kW-year.~~

T&D Deferral Benefits

Idaho Power determined the T&D deferral benefits associated with energy efficiency using 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 range 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 percent to 0.43 percent from energy efficiency programs. The 20-year average is $3.74 per kW-year. These values will be used in the calculation of energy efficiency cost-effectiveness.

6. 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. ~~The~~ 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 for the development of the HCC projects. In the 1970s and 1980s, transmission lines allowed partnerships in three coal-fired 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 variability of intermittent resources, and consequently are critical to Idaho Power's achievement of its goal to provide 100-percent clean energy by 2045.

Idaho Power's transmission interconnections provide economic benefits and improve reliability through the transfer of 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-Columbia 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 credited to customers through the PCA
- Increase revenue from sales of transmission system capacity credited to Idaho Power customers
- Increase system reliability
- Increase the ability to integrate intermittent resources, such as wind and solar
- Improve the ability to more efficiently implement advanced market tools, such as the EIM

Transmission Planning Process

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

Local Transmission Planning

Idaho Power uses a biennial process to create a local transmission plan (LTP) identifying needed transmission system additions. The LTP 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 LTP 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, and 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
6. West Central Mountains

Regional Transmission Planning

Idaho Power is active in ~~the NTTG~~NorthernGrid, a regional transmission planning ~~group.~~association of 13 member utilities. The ~~NTTG~~NorthernGrid was formed in ~~2007~~early 2020. Previously, dating back to ~~improve the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. NTTG~~2007, Idaho Power was a member of the Northern Tier Transmission Group. NorthernGrid membership includes ~~Idaho Power, Deseret~~Avista, BPA, Chelan County PUD, Grant County PUD, Idaho Power~~ Electric Cooperative, ~~, Montana–Alberta Tie Line (MATL), NorthWestern Energy, ~~PGE,~~ PacifiCorp (Rocky Mountain Power and Pacific Power), ~~Montana–Alberta Tie Line (MATL), and the Utah Associated Municipal~~Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power~~ Systems (UAMPS).~~. Biennially, ~~the NTTG~~

~~develops~~NorthernGrid will develop a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission ~~customers.~~ customers. The next regional transmission plan is expected to be published at the end of 2021.

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 6.1.

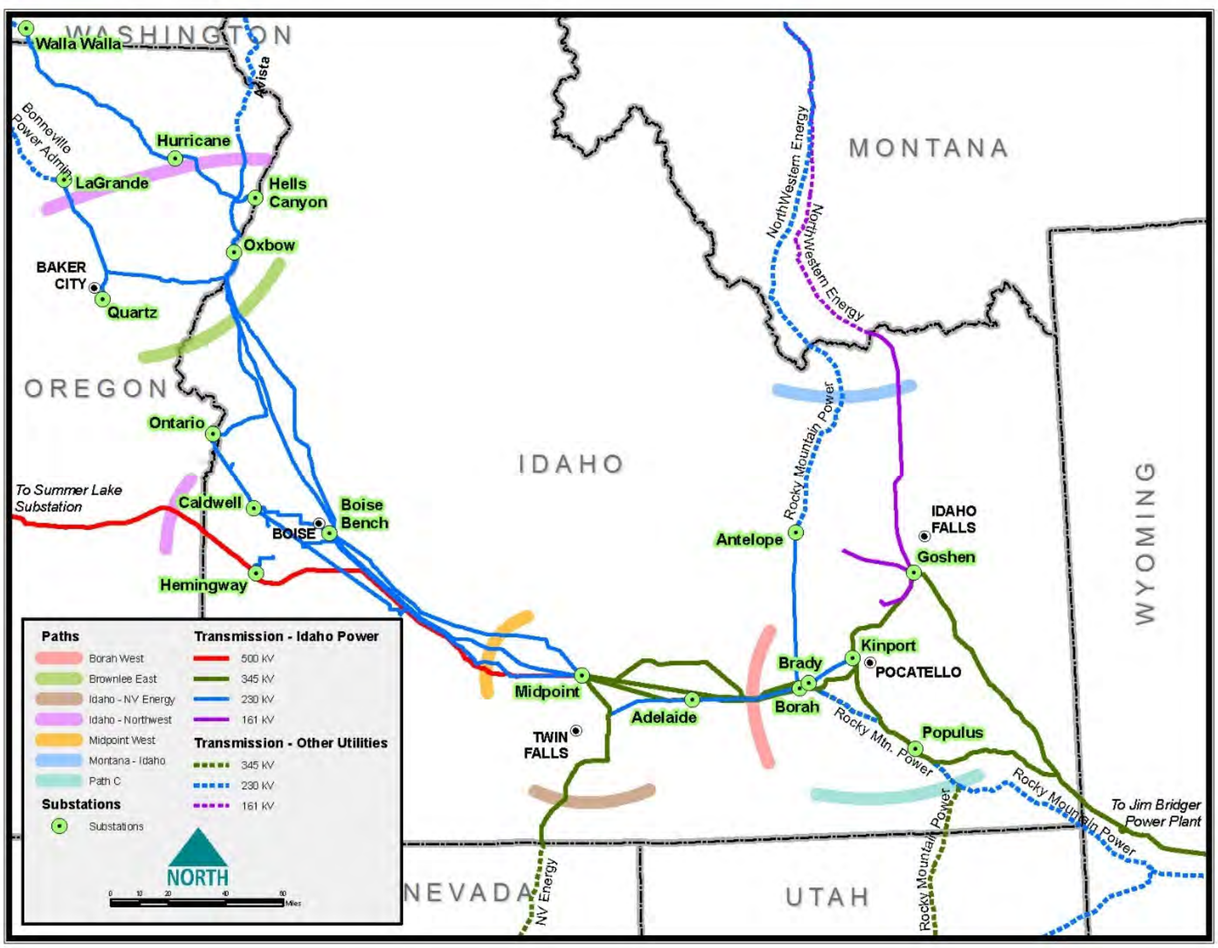


Figure 6.1 Idaho Power transmission system map

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.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho to Northwest path shown in Figure 6.1. Brownlee East is comprised of 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~~–Idaho~~ path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy south from Montana into Idaho.

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 is comprised of 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 comprised 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 comprised of 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 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. ~~Currently,~~By the ~~available~~end of 2020, the import, or northbound, capacity on the transmission path is ~~fully subscribed with Idaho Power's share of the North~~360 MW, of which Valmy ~~generation plant. However, due to infrastructure improvements, in 2020 the northbound path limit will be increased from 262 to 360 MW.~~Unit 2 utilizes approximately 130 MW.

The Jackpot Solar Project, described in the Power Purchase Agreements subsection of Chapter 3, will interconnect to this path at a substation north of the Idaho–Nevada border.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised 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 can be limited by Borah West path capacity constraints.

Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 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 can be limited by Borah West path capacity constraints.

Table 6.1 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 6.1 Transmission import capacity

Transmission Path	Import Direction	Capacity (MW)	ATC (MW)*
Idaho–Northwest	West to east	1,200	~~0~~Varies by Month
Idaho–Nevada	South to north	~~262~~360	~~0~~Varies by Month
Idaho–Montana	North to south	383	~~0~~Varies by Month
Brownlee East	West to east	1,915	Internal Path
Midpoint West	East to west	1,710	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 process, 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[11], involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300-miles long between the proposed Longhorn Station near Boardman, Oregon, and the existing Hemingway Substation 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

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

[11] 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 B2H project has been identified as a preferred resource in the past five IRPs since 2009 and ongoing permitting activities have been acknowledged in every IRP ~~short~~near-term action plan since 2009. The 2017 IRP was the first IRP to include constructed activities in the near-term action plan. The 2017 IRP ~~short~~near-term action plan, and thus, B2H construction related activities, was acknowledged by both Idaho and Oregon PUCs.

Given the importance of the B2H project, the company provides a dedicated IRP appendix, Appendix D: B2H Supplement, that provides granular detail regarding the Idaho Power's need for the project, co-participants, project history, benefits, risks, and more.

B2H is a regionally significant project; it has been identified as producing a more efficient or cost-effective plan in every ~~NTTG~~Northern Tier Transmission Group (NTTG) biennial regional transmission plan for the past 10 years. NTTG regional transmission plans produce ~~an~~a more efficient or cost-effective regional transmission plan meeting the transmission requirements associated with the load and resource needs of the NTTG footprint.

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, US Department of the Interior press release,[12] 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

In the 2019 IRP, Idaho Power requests acknowledgement of B2H based on the evaluation of Idaho Power's Oregon and Idaho native load customers funding 21 percent of the B2H project.

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

- The best future resource portfolio that included B2H was significantly better than the best future resource portfolio that did not include B2H.
- B2H provides is a big step in moving Idaho Power toward our 2045 clean energy goal
- The B2H 500-kV line adds significant regional capacity with some remaining unallocated 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

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

project manager for the B2H project. Table 6.2 shows each party's B2H capacity and permitting cost allocation.

Table 6.2 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%

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to serve eastern Idaho load from the Hemingway Substation. BPA identified six solutions—including two B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publicly announced the preferred solution to be the B2H project. The participation of three large utilities working toward the permitting of B2H further demonstrates the regional significance and regional benefits of the project. As of ~~September~~June 30, ~~2019~~2020, BPA and PacifiCorp have collectively invested over $~~71~~ 74 million towards project activities. Please refer to Appendix D for more information on project co-participants.

Figure 6.2 shows the transmission line route submitted to the ODOE in 2017.

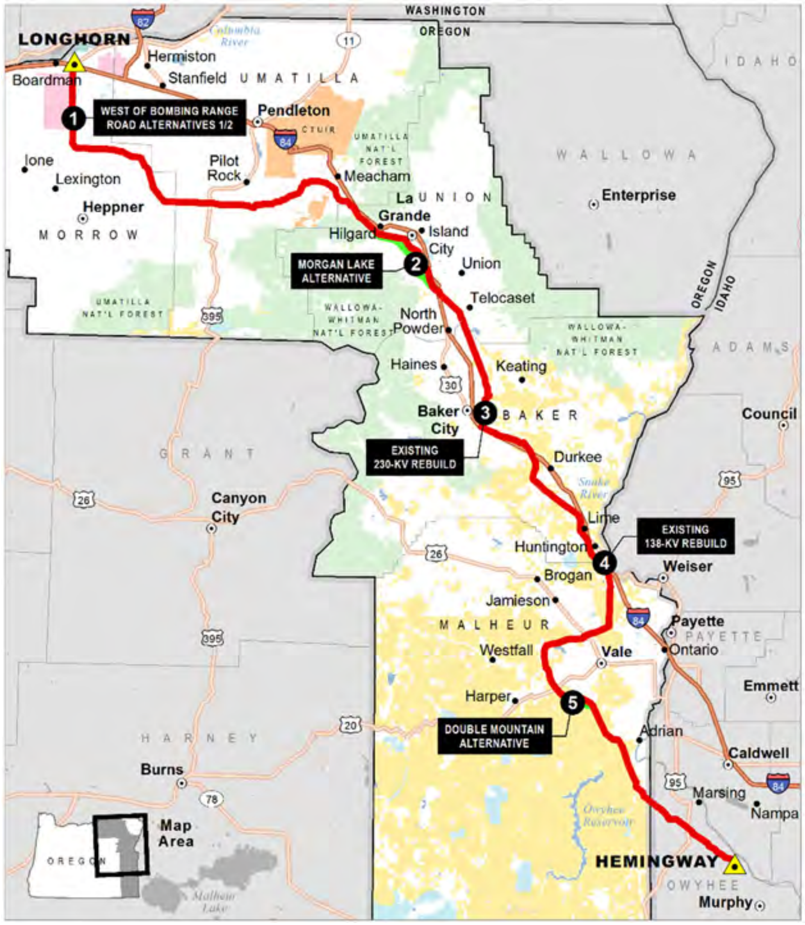


Figure 6.2 B2H route submitted in *2017 EFSC Application for Site Certificate*

Permitting Update

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), US Forest Service (USFS), ~~Department of the~~US Navy, and ODOE. 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.

The USFS issued a separate ROD on November 13, 2018 for lands administered by the USFS based on the analysis in the Final EIS. The USFS ROD approves 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 a separate ROD on September 25, 2019 for lands administered by the US Navy, based on the analysis in the Final EIS. The US Navy ROD approves the issuance of a right-of-way easement for a portion of the project that crosses the Naval Weapons System Training Facility in Boardman, Oregon.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE in February 2013 and submitted an amended pASC in summer 2017. The amended pASC was deemed complete by ODOE in September 2018. The ODOE and Energy Facility Siting Council (EFSC) reviewed Idaho Power's application for compliance with state energy facility siting standards and released a Draft Proposed Order (DPO) for B2H on May 22, 2019. The EFSC ~~will review~~reviewed the DPO findings~~ and consider~~, considered public testimony in its review and ~~issue~~issued a Proposed Order~~, which is expected in early~~ 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 2021. Permitting in Idaho will consist of a Conditional Use Permit issued by Owyhee County.

~~The Oregon permitting process is expected to last through 2021. 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 ~~DPO from the ODOE~~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 (ROW) 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 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 2017 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios. In ~~the 2019~~this *Second Amended 2019 IRP*, Idaho Power continued to model expected incremental third-party wheeling revenues as a reduction in costs ultimately borne by 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. 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 sales volume as a conservative assumption. The flat sales volume, applied to the higher FERC transmission rate, results in the cost offset for IRP portfolios with B2H.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses corresponding to Idaho Power's interest in the B2H Permit Funding Agreement, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

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 has been designated the permitting project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 6.3 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 ROW 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 worked towards construction of the 140-mile segment between the planned Aeolus substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming.

Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole 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 6.3 Gateway West map

~~Unlike the B2H project,~~ Gateway West will ~~not provide direct access to a liquid market; however, it 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 intermittent resources.

Phase 1 of the Gateway West project is expected to provide up to 1,500 MW of additional transfer capacity between Midpoint and Hemingway. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Idaho Power has a one-third interest in these capacity additions.

The Gateway West and B2H projects are complementary and will provide upgraded transmission paths from the Pacific Northwest across Idaho and into eastern Wyoming.

More information about the Gateway West project can be found at gatewaywestproject.com.

Nevada Transmission without North Valmy

The Idaho–Nevada transmission path is co-owned by Idaho Power and NV Energy, with Idaho Power having full allocation of northbound capacity and NV Energy having full allocation of southbound capacity.

~~For the 2019 IRP, Idaho Power believes the retirement of North Valmy generation plant can be adequately replaced with wholesale capacity imports across the Idaho–Nevada transmission path.~~Because the depth of the market and associated availability of resources is not as certain for the Idaho–Nevada path as it is for the Idaho-Northwest path during summer peak hours~~ so~~, import availability will ~~continue to~~ be evaluated in the ~~future~~aforementioned near-term analysis related to Valmy Unit 2. More detail on this study is provided in the Valmy Unit 2 Exit Date section of Chapter 1 of this document.

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 6.3. The assumptions about the geographic area where supply-side resources are developed determine the transmission upgrades required.

Transmission lines under construction at the Hemingway substation.

Table 6.3 Transmission assumptions and requirements

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Biomass indirect—Anaerobic digester	35	Distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	$3.5 million of distribution feeder upgrades and $1.2 million in substation upgrades.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Geothermal (binary-cycle)—Idaho	35	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.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Hydro—Canal drop (seasonal)	1	Magic Valley location connecting to 46-kV sub-transmission or local distribution feeder.	4 miles of distribution rebuild at $150,000 per mile plus $100,000 in substation upgrades.	No backbone upgrades required.

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Natural gas—SCCT frame F class (Idaho Power's peaker plants use this technology)	170	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	2-mile, 230-kV line required to connect to nearby station.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—Reciprocating gas engine Wärtsilä 34SG	18	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at 230-kV Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (1x1) F class with duct firing	300	Langley Gulch location; displaces equivalent MW of portfolio resources in same region.	New Langley–Garnet 230-kV line with Garnet 230/138 transformer and Garnet 138-kV tap line. Bundle conductor on the Langley–Caldwell 230-kV line. Reconductor Caldwell–Linden.	No additional backbone upgrades required.
Natural gas—CCCT (1x1) F class with duct firing	300	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2-mile, 230-kV line required to connect to nearby station.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (2x1) F class	550	Build new facility south of Boise (assume Simco Road area).	New 230-kV switching station with a 22-mile 230-kV line to Boise Bench Substation. Connect the 230-kV Danskin Power Plant to Hubbard line in-and-out of the new station.	Rebuild Rattle Snake to DRAM 230-kV line, rebuild Boise Bench to DRAM 230-kV line, rebuild Micron to Boise Bench 138-kV line.
Natural gas—CHP	35	Location in Treasure Valley.	1-mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—SMR	50	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. Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Pumped storage—New upper reservoir and new generation/ pumping plant	100	Anderson Ranch location; displaces equivalent MW of portfolio resources in same region.	18-mile, 230-kV line to connect to Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Solar PV—Utility-scale 1-axis tracking	30	Magic Valley location; displaces equivalent MW of portfolio resources in same region.	1-mile, 230-kV line and associated stations equipment.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
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.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.

7. Planning Period Forecasts

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

Chobani plant near Twin Falls, Idaho.

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 2019 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 2019 IRP.

The expected-case average energy (average load) and expected 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 expected, or median, case 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 expected annual average system load growth of 1.0 percent (over the period 2019 through 2038) is comprised of a residential load growth of 1.1 percent, a commercial load growth of 1.1 percent, an irrigation load growth of 0.8 percent, an industrial load growth of 0.6 percent, and an additional firm load growth of 1.2 percent.

The number of residential customers in Idaho Power's service area is expected to increase 1.7 percent annually from 464,670 at the end of 2018 to nearly 649,000 by the end of the planning period in 2038. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.1-percent average annual residential load-growth rate over the forecast term.

Significant factors that influenced the outcome of the 2019 IRP load forecast include, but are not limited to, the following:

- Weather plays a primary role in the load forecast on a monthly and seasonal basis. In the expected case load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period (i.e., normal climatology). Probabilistic variations of weather are also analyzed.

- The economic forecast used for the 2019 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. Idaho has been the fastest growth rate state in the US in terms of population in both the 2017 and 2018 measurement periods. Going into 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000 to 2004) and are expected to continue.

- 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~~reduce 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., are treated as a supply-side peaking resource).

- There continues to be significant uncertainty associated with the industrial and special contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The expected-case load forecast reflects only those industrial customers that have made a sufficient and significant binding investment indicating a commitment of the highest probability of locating in the service area. The large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the current sales and load forecast.

- The electricity price forecast used to prepare the sales and load forecast in the 2019 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2017 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2017 IRP sales and load forecast, the 2019 IRP price forecast has higher future prices. The retail prices are slightly higher throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

Weather Effects

The expected-case load forecast assumes average temperatures and precipitation over a 30-year meteorological measurement period, or normal climatology. This implies a 50-percent chance loads will be higher or lower than the expected-case 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 70^{th}- and 90^{th}-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 conditions 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 conditions are 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 in nature. Moody’s Analytics serves as 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 Moody’s data include, but are not limited to, the US 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 (or tied) growth rate of any state in the US for both 2017 and 2018. The number of households in Idaho is projected to grow at an annual rate of 1.3 percent during the forecast period, with most of the population growth centered on the Boise City–Nampa MSA. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. 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 business development strategy is focused on maximizing Idaho Power's generation resources and infrastructure by attracting new business opportunities to our service area in both Idaho and Eastern Oregon. The business development team benchmarks Idaho Power's service offerings against other utilities, 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 2019 IRP average annual system load forecast reflects continued improvement in the service-area economy. The improving economic and demographic variables driving the 2019 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 7.1 and Table 7.1 show the results of the three forecasts used in the 2019 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70th-percentile forecast, and a 10-percent probability of load exceeding the 90th-percentile forecast. The projected 20-year compound annual growth rate in the expected case forecast is 1.0 percent during the 2019 through 2038 period. The projected 20-year average compound annual growth rate in the 70th- and 90th-percentile forecasts is 1.0 percent over the 2019 through 2038 period.

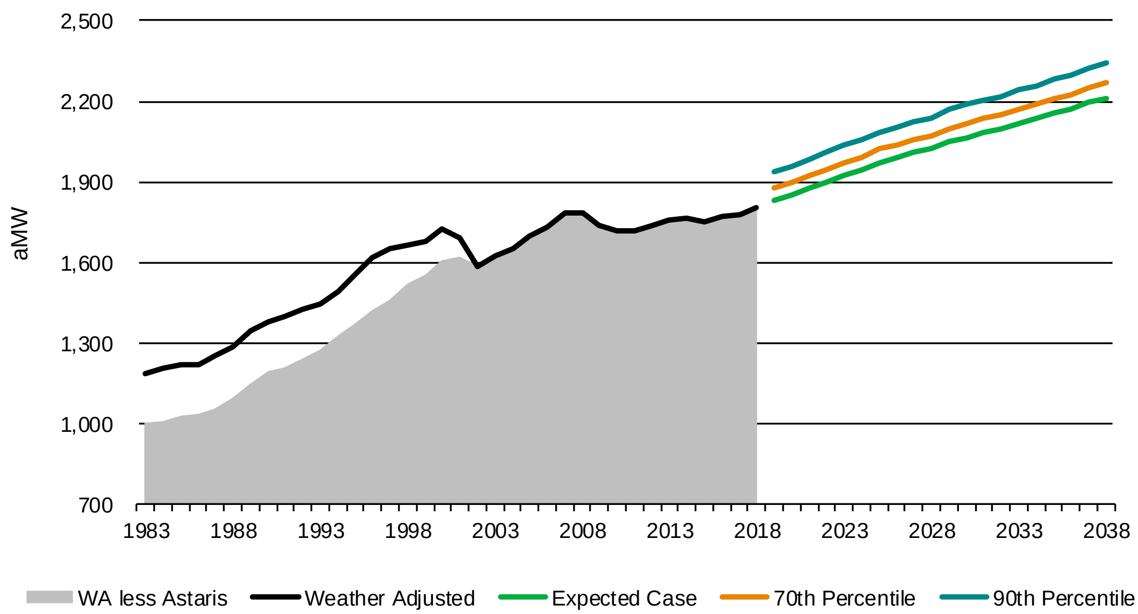


Figure 7.1 Average monthly load-growth forecast

Table 7.1 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2019	1,833	1,878	1,939
2020	1,849	1,895	1,957
2021	1,876	1,922	1,985
2022	1,899	1,946	2,010
2023	1,923	1,970	2,035
2024	1,946	1,994	2,059
2025	1,972	2,021	2,087
2026	1,990	2,039	2,106
2027	2,008	2,057	2,125
2028	2,022	2,072	2,140
2029	2,048	2,098	2,167
2030	2,066	2,117	2,187
2031	2,084	2,136	2,206
2032	2,096	2,148	2,218
2033	2,117	2,169	2,241
2034	2,134	2,187	2,259
2035	2,154	2,208	2,280
2036	2,168	2,222	2,295
2037	2,194	2,249	2,322
2038	2,212	2,267	2,342
Growth Rate (2019–2038)	**1.0%**	**1.0%**	**1.0%**

Peak-Hour Load Forecast

The average-energy load forecast, as discussed in the preceding section, is an integral component to the load forecast. The peak-hour load forecast is similarly integral. Peak-hour forecasts are expressed as a function of the sales forecast, as well 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—3,422 MW—was recorded on Friday, July 7, 2017, at 5:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011—the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summer have also been effective at reducing peak demand. The 2019 IRP load forecast projects annual peak-hour load to grow by nearly 50 MW per year throughout the planning period assuming a 1 in 20 (95th percentile) weather probability case on the day in which the annual peak-hour occurs. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance in a manner similar to a supply-side resource.

Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m., matching the previous record peak dated December 10, 2009, at 8:00 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 7.2 and Table 7.2 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.

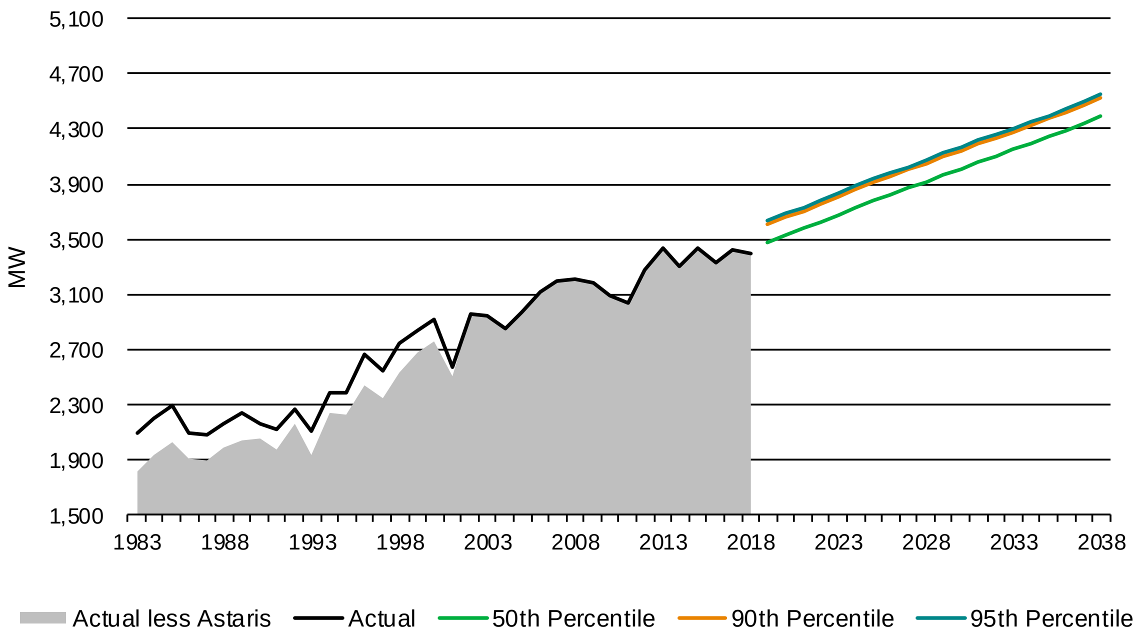


Figure 7.2 Peak-hour load-growth forecast (MW)

Table 7.2 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2018 (Actual)	3,392	3,392	3,392
2019	3,479	3,610	3,634
2020	3,528	3,659	3,683
2021	3,576	3,707	3,731
2022	3,627	3,757	3,782
2023	3,677	3,808	3,832
2024	3,732	3,863	3,887
2025	3,780	3,911	3,935
2026	3,825	3,956	3,980
2027	3,870	4,001	4,026
2028	3,918	4,048	4,073
2029	3,966	4,097	4,121

Year	Median	90th Percentile	95th Percentile
2030	4,012	4,143	4,167
2031	4,058	4,189	4,213
2032	4,103	4,234	4,258
2033	4,146	4,277	4,301
2034	4,193	4,324	4,348
2035	4,242	4,372	4,397
2036	4,291	4,422	4,446
2037	4,340	4,471	4,495
2038	4,388	4,519	4,544
Growth Rate (2019–2038)	**1.2%**	**1.2%**	**1.2%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,479 MW in 2019 to 4,388 MW in 2038—an average annual compound growth rate of 1.2 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.2 percent.

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); and the INL. These three 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 5,900 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 (QA); 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 employees over 3,500 workers throughout its locations.

INL

INL is one of the US 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, located approximately 50 miles west of Idaho Falls. INL is recognized as a critical economic driver and important asset to the state of Idaho and is the fifth largest employer in the state of Idaho with an estimated 4,100 employees.

Generation Forecast for Existing Resources

Hydroelectric Resources

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

Idaho Power uses two primary models to develop future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50th-, 70th-, and 90th-percentile modeled ~~streamflows~~stream flows are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2019 IRP is included in *Appendix C—Technical Appendix*.

Streamflow trends in the upper Snake River Basin have been in decline for several years. Those declines are mirrored in documented declines in the ESPA. Water supply increased in 2016 and a significant runoff in 2017 resulted in Snake River flows at the King Hill gage exceeding 32,000 cfs (average peak 22,900 cfs). Water conditions in 2016 and 2017 allowed for large volumes of water to be diverted to aquifer recharge operations. The large runoff event in 2017 also resulted in a significant natural recharge event. Since 2015, water levels have improved throughout much of the ESPA. Improvement was noted in reach gains in 2016 and 2017; however, 2015 had near-record lows for some gaged springs. The increases are significant, but reach gains remain below long-term historic median flows.

A water management practice affecting Snake River ~~streamflows~~stream flows involves 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 more closely 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. Because worse-than-median water is assumed in the IRP, and because of the importance of July as a resource-constrained month, 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. Additionally, flow augmentation shortages in the upper Snake River Basin are filled from the Boise River Basin if adequate water is available.

Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 7.3 shows historical April-to-July Brownlee inflow as well as modeled Brownlee inflow for the 50^{th}, 70^{th}, and 90^{th} percentiles. 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.

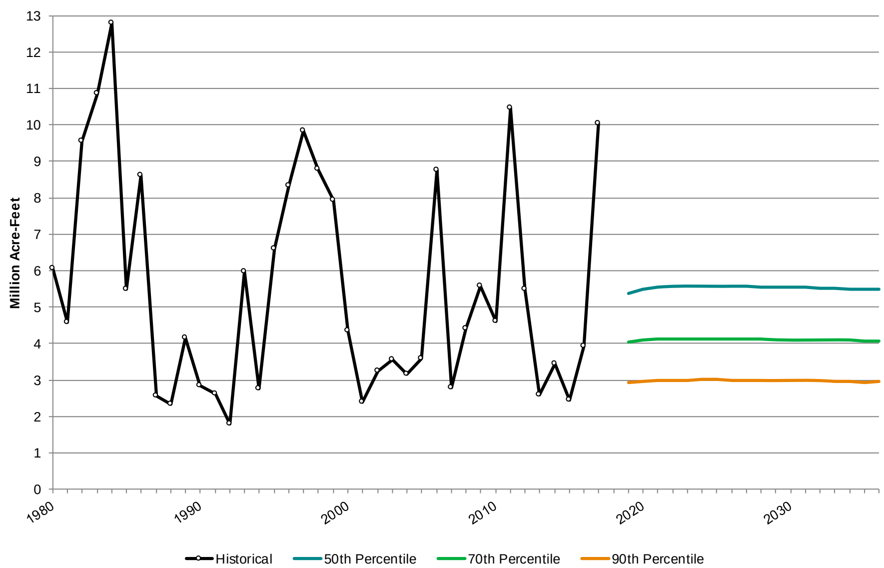


Figure 7.3 Brownlee inflow volume historical and modeled percentiles

Climate Change

Idaho Power recognizes the need to assess the impacts a changing climate may have on our resource portfolio and adaptively manage changing conditions. Idaho Power stays current on the rapidly developing climate change research in the Pacific Northwest. In 2018, two federal agency reports were issued on the potential impacts of climate change. The Fourth National Climate Assessment[13] and the River Management Joint Operating Committee (RMJOC)[14], Second Edition, Part 1 report addressed water availability in the Pacific Northwest under multiple climate change and response scenarios. Both reports highlighted the uncertainty related to future climate projections. However, most of the model projections show warming temperatures and increased precipitation into the future. The studies showed 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.

Idaho Power hydrogeneration facilities are at the lower end of a highly managed river system. Numerous reservoirs, diversions, and consumptive uses have resulted in changes to the timing of the natural hydrograph. For the 2019 IRP, Idaho Power performed a climate change analysis using datasets resulting from the RMJOC, Second Edition, Part 1 report to determine the impacts to the regulated streamflow through our system. Idaho Power used the University of Washington's modeled natural flow (hydro.washington.edu/CRCC/) and the SRPM to develop an average regulated streamflow into Brownlee Reservoir under projected future climates. The analysis included the evaluation of results from numerous general circulation models. The key findings of this analysis showed the following:

[13] nca2018.globalchange.gov/downloads/

[14] bpa.gov/p/Generation/Hydro/hydro/cc/RMJOC-II-Report-Part-I.pdf

1. Reservoir regulation from systems above Idaho Power significantly dampens the effects of a potential shift in timing of natural runoff.
2. On average, July through January regulated streamflow is unaffected, February through May regulated streamflow shows an increase, and June shows a decrease in streamflow.
3. Most models analyzed agree in showing an average annual increase in streamflow volume.

Coal Resources

In the 2019 IRP, Idaho Power ~~continues~~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 having 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 expressed glide path away from coal and long-term goal to provide 100-percent clean energy by 2045.

Boardman

The 2019 IRP assumes Idaho Power exits its share of the Boardman plant at year-end 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with regional-haze regulations on particulate matter, SO_2, and NOx emissions; the agreement stipulates that coal-fired operations will cease at the plant by year-end 2020.

~~North Valmy~~

~~The 2019 IRP assumes Idaho Power ceases participation in North Valmy Unit 1 at year-end 2019 and Unit 2 no later than year-end 2025. This assumption is consistent with the company's regulatory filings in both jurisdictions that adjust customer rates to recover the incremental annual levelized revenue requirement associated with the early cessation of operations at North Valmy. Exit from Unit 2 earlier than 2025 was evaluated as part of the AURORA capacity expansion modeling; however, the AURORA model did not select Unit 2 for exit earlier than 2025 in any portfolio.~~

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 in 2021 and 2022 for continued unrestricted operations through 2034. The SCR investments on units 1 and 2 are not currently planned or included in the IRP analysis. PacifiCorp has submitted an application to the State of Wyoming for a Regional Haze Reassessment, which could provide an alternative to SCR installation on units 1 and 2.

In the AURORA-based LTCE modeling used to develop the 24 resource portfolios in the 2019 IRP, it was assumed that the Jim Bridger units could be selected for exit dates before 2034. The

AURORA modeling included the costs of continued capital investment and accelerating the remaining book value of a unit identified for early exit to the year of exit. Additionally, an estimate of Bridger Coal Company costs was made based on the volume of coal burned, and if the burn was ~~materially~~ below the base mine plan a cost adder was included. The shared facilities costs are not included in the early unit exit decisions nor are SCR investments in units 1 and 2. The endogenous modeling of possible early exit dates was subject to the following guidelines intended to reflect a feasible exit:

- Unit 1—exit from participation 2022 through 2034
- Unit 2—exit from participation ~~2024~~2026 through 2034
- Unit 3—exit from participation ~~2026~~2028 through 2034
- Unit 4—exit from participation ~~2028~~2030 through 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.

North Valmy

The 2019 IRP assumes Idaho Power ceases participation in North Valmy Unit 1 at year-end 2019 and Unit 2 in year-end 2022 and no later than year-end 2025. Exit from Unit 2 earlier than 2025 was evaluated as part of the AURORA capacity expansion modeling, but the AURORA model did not select Unit 2 for exit earlier than 2025 in any portfolio. However, when subsequent manual portfolio adjustment was conducted by moving the exit date for Valmy Unit 2 forward to 2022, the AURORA hourly costing analysis demonstrated that the present value portfolio costs can be reduced. While these results indicate a 2022 exit date for Valmy Unit 2 is possible, Idaho Power believes it is appropriate to undertake further Valmy Unit 2 analysis in the coming months before committing to 2022 as optimal exit timing. To determine the optimal exit timing for Valmy Unit 2, Idaho Power will conduct a near-term analysis that will explore exit economics and the provision of reliable, affordable power to customers. More detail on this study is provided in the Valmy Unit 2 Exit Date section of Chapter 1 of this document.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT, having combined nameplate capacity of 762 MW. The SCCT units are typically operated during peak-load events in the summer and winter. With respect to peaking capacity, ~~they~~the SCCT units are assumed capable of producing an on-demand peak capacity of 416 MW, which is recognized by the AURORA model as contributing to the planning margin in capacity expansion modeling.

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. Langley Gulch is forecast to contribute ~~270~~300 MW of on-demand peaking capacity available as contribution to the planning margin in capacity expansion modeling.

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 7.3 provides excerpts from IRP and avoided-cost filings, as an indication of the approaches used to forecast natural gas prices.

Table 7.3 Utility peer natural gas price forecast methodology

Utility	Gas Price Forecast Methodology
Rocky Mountain Power 2017 IRP	The October 2016 natural gas Official Forward Price Curve (OFPC), which was used in the 2017 IRP, was based on an expert third-party long-term natural gas forecast issued August 2016.
Avista Electric 2017 IRP	Avista uses forward market prices and a forecast from a prominent energy industry consultant to develop the natural gas price forecast for this IRP.
Avista Gas 2016 Natural Gas IRP	Avista reviewed several price forecasts from credible sources and created a blended price forecast to represent an expected price strip.
Portland General Electric (PGE) 2016 IRP	PGE derived the Reference Case natural gas forecast from market forward prices for the period 2017 through 2020 and the Wood Mackenzie long-term fundamental forecast for the period 2022 through 2035. A transition from the market price curve to Wood Mackenzie's long-term forecast is made by linearly interpolating for one year (2021).
Northwest Natural 2018 Oregon IRP	NW Natural's 2018 IRP natural gas forecast is of monthly prices developed by a third-party provider (IHS) based on market fundamentals. Cited source extracted from IHS Global Gas service and was developed as part of an ongoing subscription.
Intermountain Gas 2017 IRP	2017–2021 forecast based on an average of three five-year price forecasts for the Alberta Energy Company (AECO), Rockies, and Sumas pricing points from three different energy companies based on the May 26, 2016 market close.
Cascade Natural Gas Company 2018 Oregon IRP	Cascade's long-term planning price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. The fundamental forecasts include Wood Mackenzie, EIA, the Northwest Power and Conservation Council (NWPCC), Bentek (a S&P Global company), and the Financial Forecast Center's long-term price forecasts.

Based on the methodologies employed by Idaho Power's peer utilities, as well as feedback received during IRPAC meetings for the 2019 IRP, Idaho Power made the decision to enlist the service of a well-known third-party vendor as the source for the IRP planning case natural gas price forecast.

Idaho Power invited a representative of the third-party vendor to present to the IRPAC on October 11, 2018. The Platts forecast information below was presented by the vendor representative at the October 2018 IRPAC meeting.

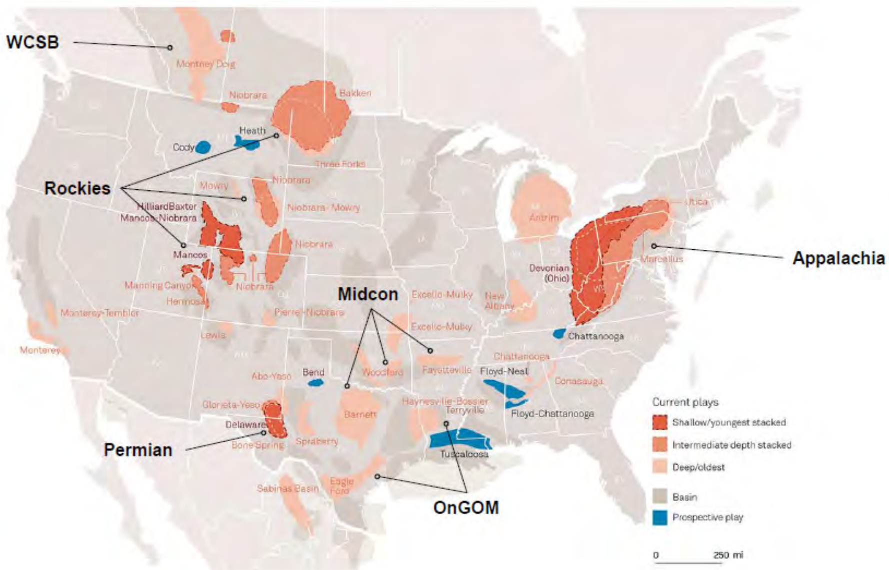
The third-party vendor uses the following inputs/techniques to develop its gas price forecast:

- 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 (160 supply areas, 272 pipelines, 444 storage areas, and 694 demand centers) 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 ~~that informed~~helped inform the third-party ~~vendor uses~~ 2018 natural gas price forecast ~~include~~ used in the IRP analysis:

- Greater regionalization, with Gulf (export) dominance waning
- Status of North American major gas basins
- The emergence of the Northeast as a self-sufficient region, with a risk of periodic surplus and a chronic need for additional markets
- Texas/Southeast flow reversal to accommodate growing exports
- The absence of policy-driven demand growth (carbon), causing the Midwest to act as a "way station" for surplus gas
- The western US approaches saturation on policy limits, requiring West-coast liquefied natural gas (LNG) exports to lift demand
- Projected slowing of ramp in Appalachian pipeline use
- Northeast prices increasingly influenced by supply competition and energy transition, rather than pipe congestion
- The Permian basin may be overwhelmed by too much takeaway pipe if all projects are built
- Congestion and competition depress upstream prices in the West, while California ultimately competed with the premium Gulf
- Ample Midwest supply caps Chicago prices, while resource depletion supports the in-basin price of Rockies supply
- West-to-East disconnect in Canada, means that growth opportunities for Western Canadian Sedimentary Basin are tied to LNG aspirations
- Rising midstream costs have enabled diverse sources of supply to compete



S&P Global Platts

Figure 7.4 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 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 and NYMEX), Idaho Power concluded that the third-party vendor's natural gas forecast is appropriate for the planning case forecast in the 2019 IRP.

The third-party vendor's 2018 Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington (the location from which most of the supply is procured to fuel the company's fleet of natural gas generation in Idaho), served as the planning case forecast of fueling costs for existing and potential new natural gas generation on the Idaho Power system.

Natural Gas Transport

Ensuring pipeline transportation capacity will be available for future natural gas-fired generation needs will require the reservation of pipeline capacity before a prospective resource's in-service date. Idaho Power believes that turnback pipeline capacity from Stanfield, Oregon to Idaho could serve the need for natural gas-fired generating capacity for up to 600 megawatts (MW) of installed nameplate capacity. Williams' Northwest Pipeline has recently entered into 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 additional natural gas-fired 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 (existing contracts expiring without renewal) 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-fired generating capacity, a pipeline expansion would provide diversification benefits from the current mix of firm transportation composed of 60 percent from British Columbia, 40 percent 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)/day. Idaho Power applied this rate to potential natural gas-fired generation types with an assumption of high capacity factor (100 percent capacity coverage), medium capacity factor (33 percent), and low capacity factor (25 percent). 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 percent of the requirements on any given day.

Analysis of IRP Resources

The electrical energy sector has experienced considerable transformation during the past 10 to 15 years. VERs, such as wind and solar, have markedly expanded their market penetration during this period, and through this expansion have affected the wholesale market for electrical energy. The expansion of VERs has also highlighted the need for flexible capacity resources to provide balancing. A consequence of the expanded penetration of VERs is periodic energy oversupply alternating with energy undersupply. Flexible capacity is primarily provided by dispatchable thermal resources (coal- and natural gas-fired), hydro resources, and energy storage resources.

For the 2019 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 capability to provide flexible capacity, the system attributes analyzed include the capability 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 intermittent production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are compared 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 Total Resource Cost (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 in the best interest of Idaho Power 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 allowance for funds used during construction (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 Appendix*.

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 LCOC values for the potential IRP resources are provided in Figure 7.5.

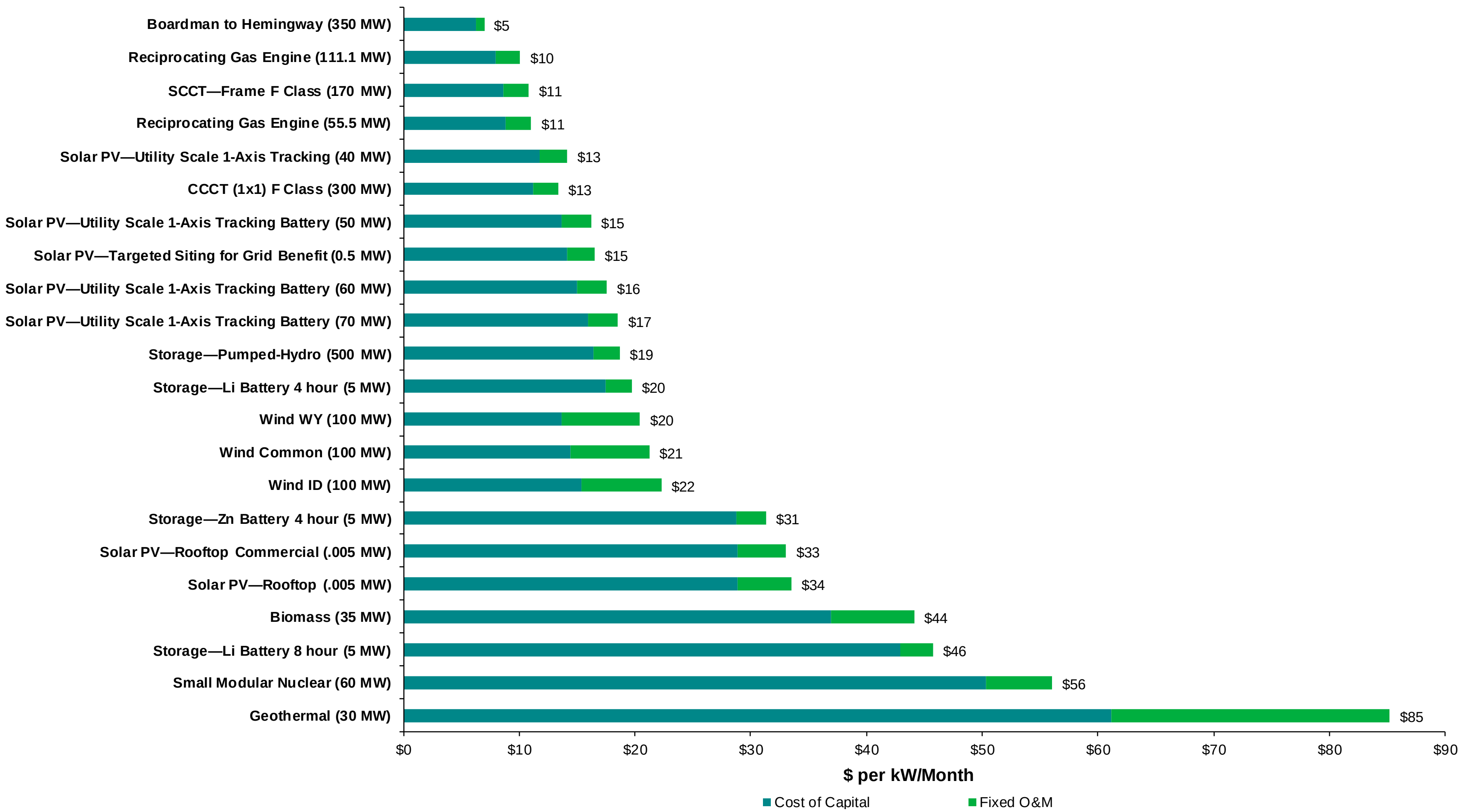


Figure 7.5 Levelized capacity (fixed) costs in 2019 dollars[15]

[15] Levelized capacity costs are expressed in terms of dollars per kW of *installed* capacity per month. 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.

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 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, integration costs for wind and solar resources, and wholesale energy for B2H. The cost of recharge energy for storage resources is not included in the graphed LCOE values.

The LCOE is provided assuming a common on-line date of 2023 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 use of the common on-line date five years into the IRP planning period allows the LCOE analysis to capture projected trends in resource costs. 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.

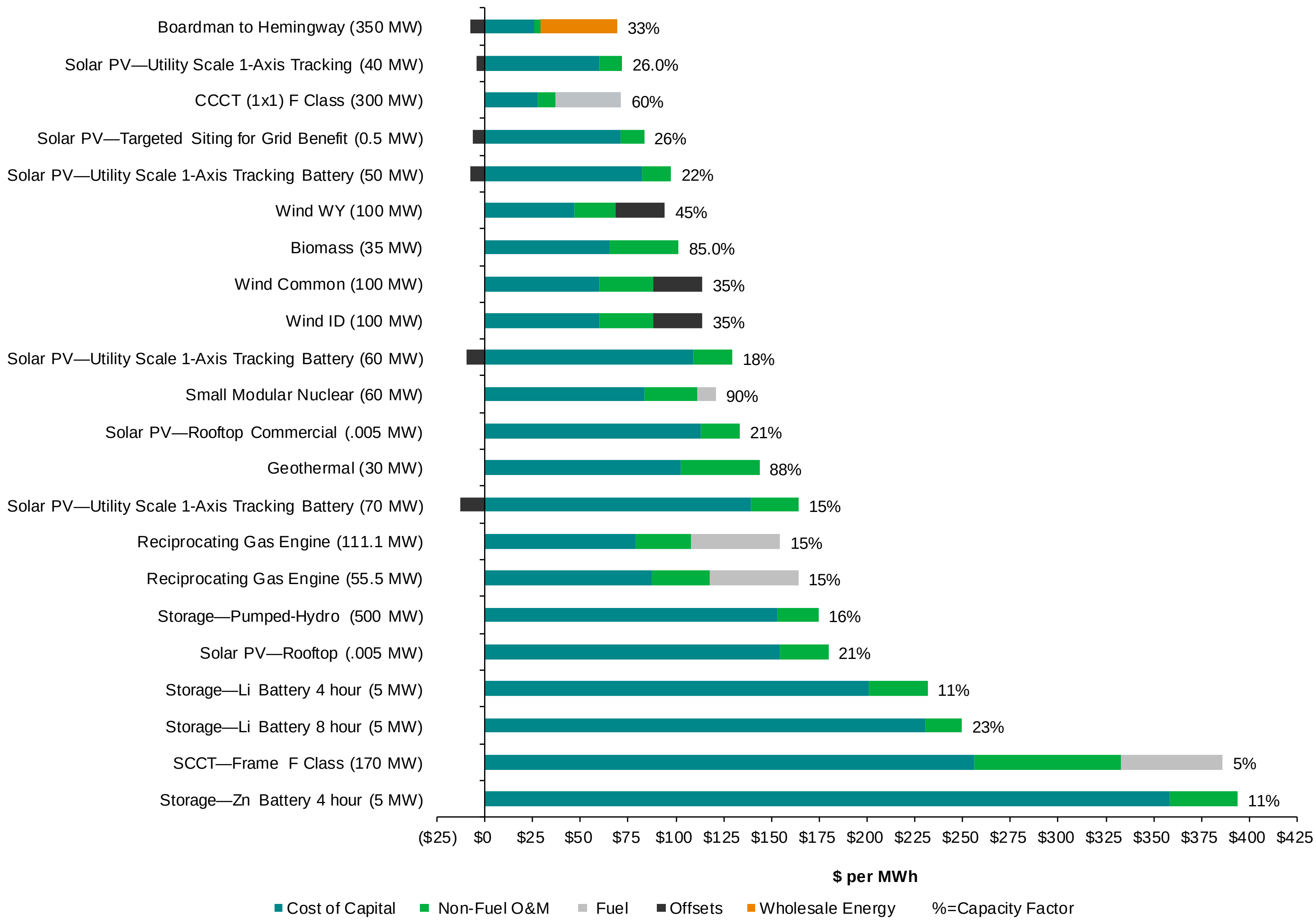


Figure 7.6 Levelized cost of energy (at stated capacity factors) in 2023 dollars

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 intermittent renewable resources, 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 $23 per month per kW of installed capacity.[16] However, assuming wind delivers peaking capacity equal to 5 percent of installed capacity, the LCOC ($23/month/kW) converts to $460 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 less dependably deliver during the high-value peak-loading periods; in effect, the energy delivered from wind tends to be of lesser value than that delivered from biomass, and because of this difference caution should be exercised when comparing LCOEs for these resources.

In recognition of differences between resource attributes, potential IRP resources for the 2019 IRP are classified based on their attributes. The following resource attributes are considered in this analysis:

- *Intermittent renewable*—Renewable resources, such as wind and solar, characterized by intermittent output and 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 intermittent renewable resources
- *Energy-providing*—Resources producing relatively predictable energy when averaged over long time periods (i.e., monthly or longer)

Table 7.4 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.

[16] The units of the denominator can be expressed in reverse order from the cost estimates provided in Figure 7.5 without mathematically changing the cost estimate.

Table 7.4 Resource attributes

Resource	Intermittent Renewable	Dispatchable Capacity-Providing	Non-Dispatchable (Coincidental) Capacity-Providing[17]	Balancing/ Flexibility-Providing	Energy-Providing	Size Potential
Biomass—Anaerobic Digester		✓			✓	Scalable up to about 50 MW
B2H		✓		✓	✓	(200 MW Oct–March, 500 MW April–Sept)
Demand Response		✓				Scalable up to 50 MW
Energy Efficiency			✓		✓	Scalable up to achievable potential
Geothermal		✓			✓	Scalable up to about 50 MW
CCCT (1x1)		✓		✓	✓	300 MW increments
SCCT—Frame F Class		✓		✓		170 MW increments
Reciprocating Gas Engine		✓		✓	✓	~~18~~55.5 MW increments
Small Modular Nuclear		✓		✓	✓	60 MW increments
Solar PV—Rooftop	✓		✓		✓	Scalable
Solar PV—Utility-Scale 1-Axis Tracking	✓		✓		✓	Scalable
Solar PV—Targeted Siting for Grid Benefit	✓		✓		✓	Scalable up to ~~about~~ 10 MW
Solar PV—AC Coupled with Lithium Battery	✓	✓			✓	Scalable
Storage—Pumped Hydro		✓		✓	✓	500 MW increments
Storage—Lithium Battery		✓		✓		Scalable
Wind (Wyoming/Idaho)	✓				✓	Scalable

[17] 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.

8. Portfolios

Prior to commencing modeling for this *Second Amended 2019 IRP*, Idaho Power conducted a four-step review of IRP model inputs, system settings and specifications, and model verification and validation. 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 *Second Amended 2019 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 2019 IRP, Idaho Power used the LTCE capability of AURORA to produce WECC-optimized portfolios under various future conditions for natural gas prices and carbon costs. It is important to note that although the logic of the LTCE model optimizes resource additions based on the performance of the WECC as a whole, the resource portfolios produced by the LTCE and examined in this IRP are specific to Idaho Power. In other words, the term "WECC-optimized" refers to the LTCE model logic rather than the footprint of the portfolios being examined. Based on this definition, the WECC-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 WECC-optimized portfolios maintains sufficient reserves as defined in the model. To ensure the AURORA-produced WECC-optimized portfolios provide the least-cost, least-risk future specific to the company's customers, a subset of top-performing WECC portfolios was manually adjusted with the objective of further reducing portfolio costs specific to the Idaho Power system. This manual process is discussed further in the sections that follow.

Planning Margin

The 2019 IRP uses the LTCE capability of the AURORA model to develop portfolios compiled of different resource combinations. The model selects portfolios based on standards, policies, and resources needed- and does so in the least-cost manner. Idaho Power selected a 50th percentile hourly load forecast for the Idaho Power area and a 15 percent peak-hour planning margin to develop a 20-year, WECC optimized resource portfolios under a range of futures. The WECC portfolio includes a specific set of new resources and resource exits to reliably serve Idaho Power's load over the planning timeframe. Each portfolio is constrained by the peak-hour capacity planning margin and hourly flexibility requirements. As noted above, manual refinements to top-performing WECC optimized resource portfolios are used to ensure the least-cost, least-risk option has been identified specific to Idaho Power's service area.

Several factors influenced Idaho Power's decision to move to a 15 percent peak-hour planning margin in the 2019 IRP. The use of a percentage-based planning margin is a good fit with the use and logic in the AURORA model's LTCE functionality used in portfolio development. First, it is consistent with the NERC's N-1 Reserve Margin criteria.[18] Second, it is similar to the methodologies employed by Idaho Power's regional peer utilities for capacity planning.[19]

To validate the change from the prior IRP methodology, Idaho Power compared the 2017 IRP's 95th percentile peak-hour capacity, including the addition of 330 MW of capacity benefit margin (CBM) to the 50th percentile peak-hour forecast with a 15 percent planning margin as used in the 2019 IRP. As shown in Figure 8.1, the two methods do not result in significant differences. The series composed of the 95th percentile peak-hour value plus the 330 MW CBM does not include operating reserve obligations, which would be approximately 200 MW for a system load of 3,600 MW and higher for growing system loads.

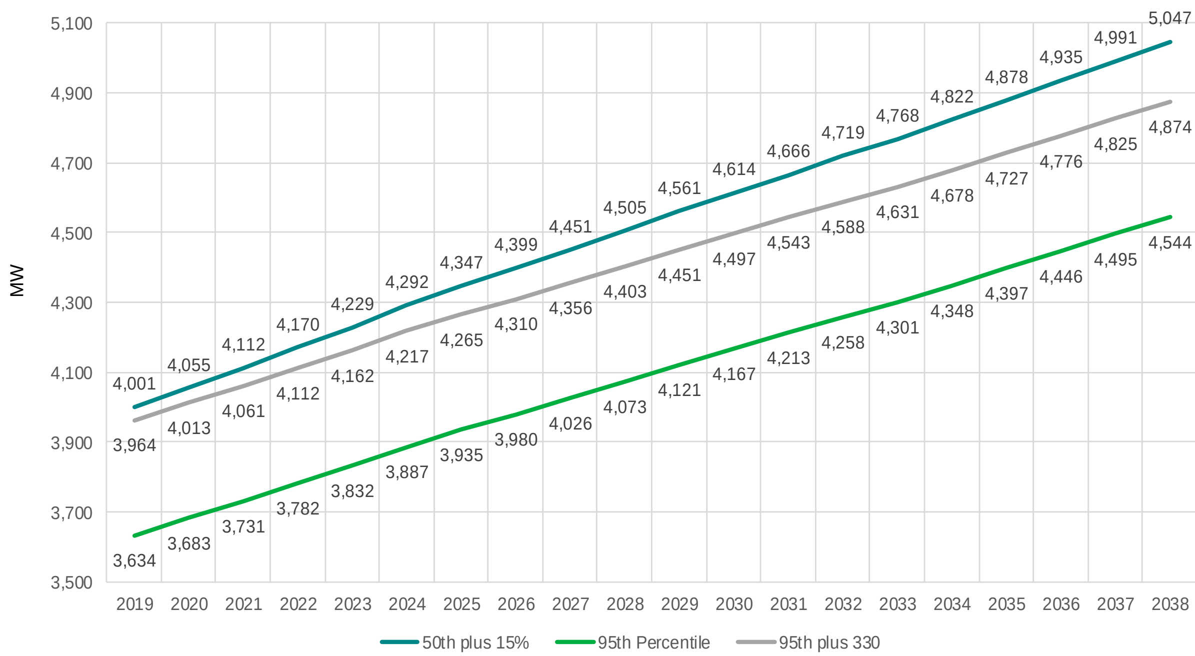


Figure 8.1 2017 versus 2019 IRP planning margin comparison (MW)

Portfolio Design Overview

The AURORA LTCE process develops future portfolios under varying future conditions for natural gas prices and carbon costs, selecting resources while applying planning margins and regulating reserve constraints, all with the objective of finding the least-cost solution. The future resources available possess a wide range of operating characteristics, and development and environmental attributes. The impact 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.

[18] nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

[19] PacifiCorp 13-percent target planning margin (2017 IRP page 10), PGE 17 percent reserves planning margin (2016 IRP page 116), and Avista 14 percent planning margin (2017 IRP 6-1).

The use of an LTCE model that optimizes portfolio buildouts for the entire WECC region led the company to develop additional portfolios to ensure that it had reasonably identified an optimal solution specific to its customers. To accomplish this, a subset of top-performing WECC-optimized portfolios were manually adjusted with the objective of further reducing Idaho Power-specific portfolio costs while maintaining reliability. This method is described in greater detail in Chapter 9. The portfolios were then evaluated for operational, environmental, and qualitative considerations. The evaluation of the resources and portfolios culminate in an action plan that sets the stage for Idaho Power to economically and effectively prepare for the system needs of the future.

Previous IRP portfolio development included a concurrent evaluation of resource characteristics: quantitative and qualitative measures and risks when selecting a resource for inclusion in a specific portfolio for a future planning scenario. These portfolios were developed under low hydro and high peak forecast percentiles while considering the combined qualitative risks and various resource characteristics.

Using the AURORA LTCE process in portfolio design has some improvements compared to the prior resource selection methodology. The AURORA portfolio development process is more precise in using the defined resource characteristics and established quantitative requirements associated with those resources. Examples include increasing regulation requirements with solar generation additions or maintaining a peak hour planning margin and applying hourly regulating reserve requirements in the economic selection and timing of resource additions and retirements. Additionally, the LTCE process allowed the company and stakeholders to evaluate a relatively large number of portfolios relative to prior IRPs. In 2017, for example, the IRP examined 12 portfolios that were manually selected. However, in the 2019 IRP, the company evaluated ~~44~~ 48 total portfolios, 24 of which were developed by the LTCE model, and ~~20~~24 that were developed during the manual refinement process.

Regulating Reserve

Idaho Power characterized regulating reserve rules as part of its 2018 study of VER integration. To develop these rules for the VER study, Idaho Power analyzed one year of 1-minute time-step historical data for customer load, wind production, and solar production (December 2016 to November 2017). Based on this analysis, the company developed rules for bidirectional regulating reserve that adequately positioned dispatchable capacity to balance variations in load, wind, and solar while maintaining compliance with NERC's reliability standard.[20] The bidirectional regulating reserve was designated RegUp for the unloaded dispatchable capacity held to balance undersupply situations (i.e., supply less than load) and RegDn for loaded dispatchable capacity held to balance oversupply situations (i.e., supply exceeding load).

For the 2019 IRP, 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

[20] NERC BAL-001-2 (nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf)

containing varying amounts of VER generating capacity (i.e., the VER-caused regulating reserve requirements are calculable). The approximations express the RegUp and RegDn as dynamic and seasonal percentages of hourly load, wind production, and solar production. The approximations used for the IRP are given in tables 8.1 and 8.2. For each hour of the AURORA simulations, the dynamically determined regulating reserve is the sum of that calculated for each individual element.

Table 8.1 RegUp approximation—percentage of hourly load MW, wind MW, and solar MW

RegUp	Winter[1]	Spring[2]	Summer[3]	Fall[4]
Load	8%	11%	7%	9%
Wind	38%	44%	48%	49%
Solar	69%	47%	53%	66%

[1]Winter: December, January, February
[2]Spring: March, April, May
[3]Summer: June, July, August
[4]Fall: September, October, November

Table 8.2 RegDn approximation—percentage of hourly load MW, wind MW, and solar MW

RegDn	Winter[1]	Spring[2]	Summer[3]	Fall[4]
Load	18%	29%	21%	29%
Wind	0%	0%	0%	0%
Solar	33%	0%	0%	0%

[1]Winter: December, January, February
[2]Spring: March, April, May
[3]Summer: June, July, August
[4]Fall: September, October, November

The RegDn rules for the VER study for wind and solar were expressed in terms of percentage of headroom above forecast production. For example, for a system having 300 MW of on-line solar capacity and forecast production for a given hour at 200 MW, the VER analysis found the percentage of 100 MW of headroom (300 to 200 MW) necessary to maintain system reliability. Given the substantial variations in VER generating capacity between portfolios, and temporally (i.e., year-to-year) within portfolios, it was impractical to approximate the RegDn regulating reserve for wind and solar production, except for the winter season for solar. It is emphasized that the regulating reserve levels used in the 2019 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.

Framework for Expansion Modeling

Idaho Power's LTCE modeling was performed under three natural gas price forecasts and four carbon price forecasts to develop optimized resource portfolios for a range of possible future conditions.

Natural Gas Price Forecasts

Idaho Power used the adjusted Platts 2018 Henry Hub natural gas price forecast as the planning case forecast in the 2019 IRP. Idaho Power also developed portfolios under two additional gas price forecasts: 1) the 2018 EIA Reference Case and 2) the 2018 EIA Low Oil and Gas (LOG) case.[21]

Carbon Price Forecasts

Idaho Power developed portfolios under four carbon price scenarios for the 2019 IRP shown in Figure 8.2:

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 a carbon price forecast from a Wood Mackenzie report[22] released in June 2018. The carbon cost forecast assumes a price of $2/ton beginning in 2028 and increases to $22 per ton by the end of the IRP planning horizon. A key assumption in the report is that carbon costs would be regulated under a federal program and no state program is envisioned.
3. Generational Carbon Cost—is EPA's estimate of the social cost of carbon from 2016.[23] The social or generational cost of carbon is meant to be a comprehensive estimate of climate change impacts and includes, among other things, changes in net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs. The generational carbon cost forecast assumes a price of $55.73 per ton starting in 2020 and increases to $101.16 per ton by the end of the IRP planning horizon.
4. High Carbon Costs—is based on the California Energy Commission's *Integrated Energy Policy Report* (IEPR) "Revised 2017 IEPR GHG Price Projections."[24] Idaho Power used the carbon price stream from the high price (low consumption) scenario and, for the 2019 IRP, assume carbon costs would begin in 2022 under a federal program. No state program is envisioned. The high carbon cost forecast assumes a price of $28.65 per ton starting in 2022 and increases to $107.87 per ton by the end of the IRP planning horizon.

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[21] EIA Annual Energy Outlook 2018, February 2018: eia.gov/outlooks/aeo/pdf/AEO2018.pdf

[22] "North America power & renewables long term outlook: Charting the likely energy transition page—the 'Federal Carbon' case."

[23] epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

[24] efiling.energy.ca.gov/GetDocument.aspx?tn=222145

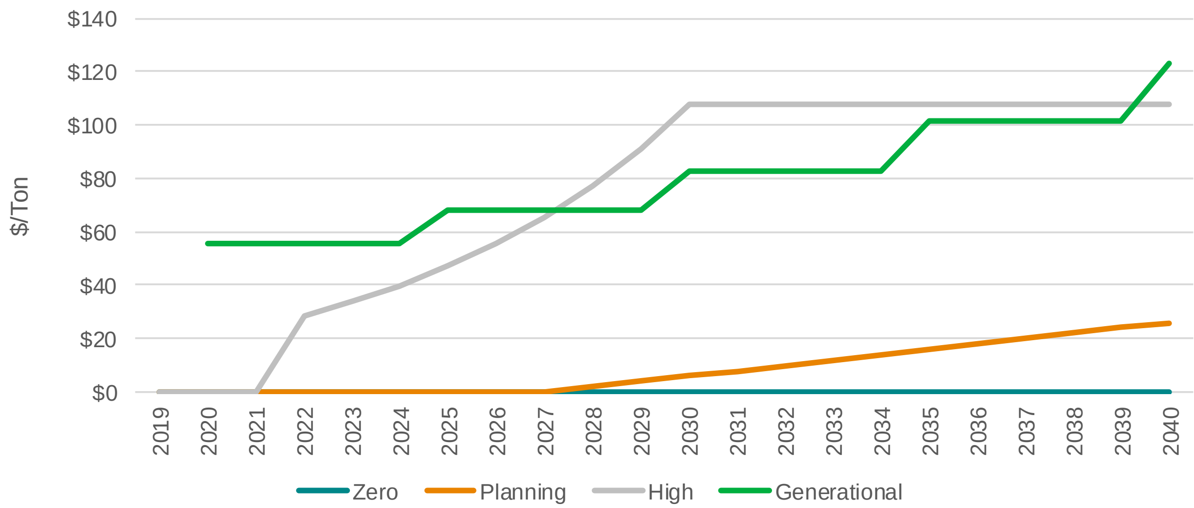


Figure 8.2 Carbon Price Forecast

Because the AURORA LTCE can evaluate generation units for economic retirement, Idaho Power provided baseline retirement assumptions in the AURORA model. The baseline retirement dates for Idaho Power's coal-fired generation is year-end 2034 for all Jim Bridger units. Any changes to these retirement dates would be determined through the portfolio modeling process.

Table 8.3 shows the 12 planned non-B2H portfolio designs resulting from the natural gas and carbon price forecasts.

Table 8.3 Non-B2H portfolio reference numbers

Non-B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	1	2	3	4
EIA Reference Gas	5	6	7	8
EIA LOG Gas	9	10	11	12

To evaluate the B2H project in the AURORA model, Idaho Power reproduced the same set of 12 portfolios with the inclusion of the B2H transmission line as a resource.

Table 8.4 shows the planned 12 B2H portfolio designs resulting from the natural gas and carbon price futures.

Table 8.4 B2H portfolio reference numbers

B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	13	14	15	16
EIA Reference Gas	17	18	19	20
EIA LOG Gas	21	22	23	24

WECC-Optimized Portfolio Design Results

The AURORA LTCE's model generated 24 different portfolios using all the assumptions described earlier. The 12 Non-B2H portfolios are shown in Figure 8.3, while the 12 B2H portfolios are shown in Figure 8.4. The details and timing of additional resources in the 24 WECC-optimized portfolios are included in *Appendix C—Technical Appendix*.

Figure 8.3 WECC-optimized portfolios 1 through 12 (non-B2H portfolios), capacity additions/reductions (MW)

Figure 8.4 WECC-optimized portfolios 13 through 24 (B2H portfolios), capacity additions/reductions (MW)

Manually Built Portfolios

~~As noted earlier in this chapter, a subset of top-performing~~Based on stakeholder feedback received following the Amended 2019 IRP process, Idaho Power adjusted its methodology for selecting WECC-optimized portfolios for manual adjustment.

Previously, Idaho Power selected four WECC-optimized portfolios (two B2H and two non-B2H) that represented the best combinations of least cost and least risk. Stakeholders noted, however, that this selection process resulted in a group of similar portfolios in terms of resource selection and timing. An alternate approach was ~~manually adjusted~~suggested: Choose a wider range of WECC-optimized portfolios for manual selection. Idaho Power adopted this approach for this *Second Amended 2019 IRP*.

To ensure a wider range of base portfolios for manual optimization, Idaho Power selected six starting points (rather than four in the Amended 2019 IRP) based on 12 WECC-optimized portfolios for manual adjustment. The six starting-point portfolios (three with B2H and three without) reflect a more diverse array of portfolios, in terms of resource amounts, timing, and type.

Idaho Power began this selection process by grouping WECC-optimized portfolios into similar "buckets" based on resource selection, noting resource similarities in Portfolios 1 and 2, 3 and 4, and 11 and 12 in the non-B2H runs and in Portfolios 13 and 14, 15 and 16, and 23 and 24 in the B2H scenarios (see Figure 8.3 and Figure 8.4). These buckets aligned to tested future conditions—Planning Gas/Planning Carbon, Planning Gas/High Carbon, and High Gas/High Carbon (See Table 8.5).

Table 8.5 WECC-Optimized Portfolios Selected for Manual Adjustments

Category	B2H Portfolios	Non-B2H Portfolios
Planning Gas, Planning Carbon (PGPC)	P(13), P(14)	P(1), P(2)
Planning Gas, High Carbon (PGHC)	P(15), P(16)	P(3), P(4)
High Gas, High Carbon (HGHC)	P(23), P(24)	P(11), P(12)

The first two categories (*Planning Gas, Planning Carbon (PGPC)* and *Planning Gas, High Carbon (PGHC)*) were based on the lowest cost portfolios from the WECC-optimization and the resources match more closely between portfolios. The *High Gas, High Carbon (HGHC)* category was added to determine whether a more optimal portfolio could be obtained when beginning with a different mix of flexibility resources (pumped hydro, biomass, and nuclear instead of natural gas).

The selected portfolio categories reflect a wide range of gas and carbon futures and B2H and non-B2H alternatives, and it allowed for robust evaluation of portfolios for manual optimization, with the objective of further reducing Idaho Power-specific portfolio costs while maintaining reliability ~~further reduction in Idaho Power-specific portfolio costs. The selected subset is composed of the following four portfolios with their associated natural gas and carbon futures, as well as their designation with respect to inclusion of B2H:~~.

- ~~Portfolio 2 (Planning Gas, Planning Carbon, without B2H)~~
- ~~Portfolio 4 (Planning Gas, High Carbon, without B2H)~~
- ~~Portfolio 14 (Planning Gas, Planning Carbon, with B2H)~~
- ~~Portfolio 16 (Planning Gas, High Carbon, with B2H).~~

~~The analysis supporting the selection of these four portfolios for manual adjustment as well the process followed in manually adjusting the WECC portfolios, is discussed in the following chapter.~~

9. MODELING ANALYSIS

Portfolio Cost Analysis

Once the WECC-Optimized 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 cannot be performed simultaneously within the AURORA model due to the large computing requirements needed to perform the complex calculations inherent within the LTCE model.

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. The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 9.1 Financial assumptions

Plant Operating (Book) Life	Expected life of asset
Discount rate (weighted average capital cost)	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
Emission adder escalation rate	3.00%
General O&M escalation rate	2.20%
Annual property tax ~~escalation~~ rate (% of investment)	0.~~29~~49%
B2H annual property tax rate (% of investment)	0.55%
Property tax escalation rate	3.00%
B2H property tax escalation rate	1.67%
Annual insurance premium (% of investment)	0.~~31~~03%
B2H annual insurance premium (% of investment)	0.03%
Insurance escalation rate	2.00%
B2H insurance escalation rate	2.00%
AFUDC rate (annual)	7.65%

The 24 WECC-optimized portfolios designed under the AURORA LTCE process were run through four different hourly simulations shown in Table 9.2.

Table 9.2 AURORA hourly simulations

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

The purpose of the AURORA hourly simulations is to compare how portfolios perform under scenarios different from the scenario assumed in their initial design. For example, a portfolio initially designed under Planning Gas and Planning Carbon should perform better relative to other portfolios under a Planning Gas and Planning Carbon ~~scenario~~price forecast than under a High Gas and High Carbon ~~scenario.~~price forecast. The compiled results from the four hourly simulations, where only the pricing forecasts were changed, are shown in Table 9.3.

Table 9.3 2019 IRP WECC-optimized portfolios, NPV years 2019–2038 ($ x 1,000)

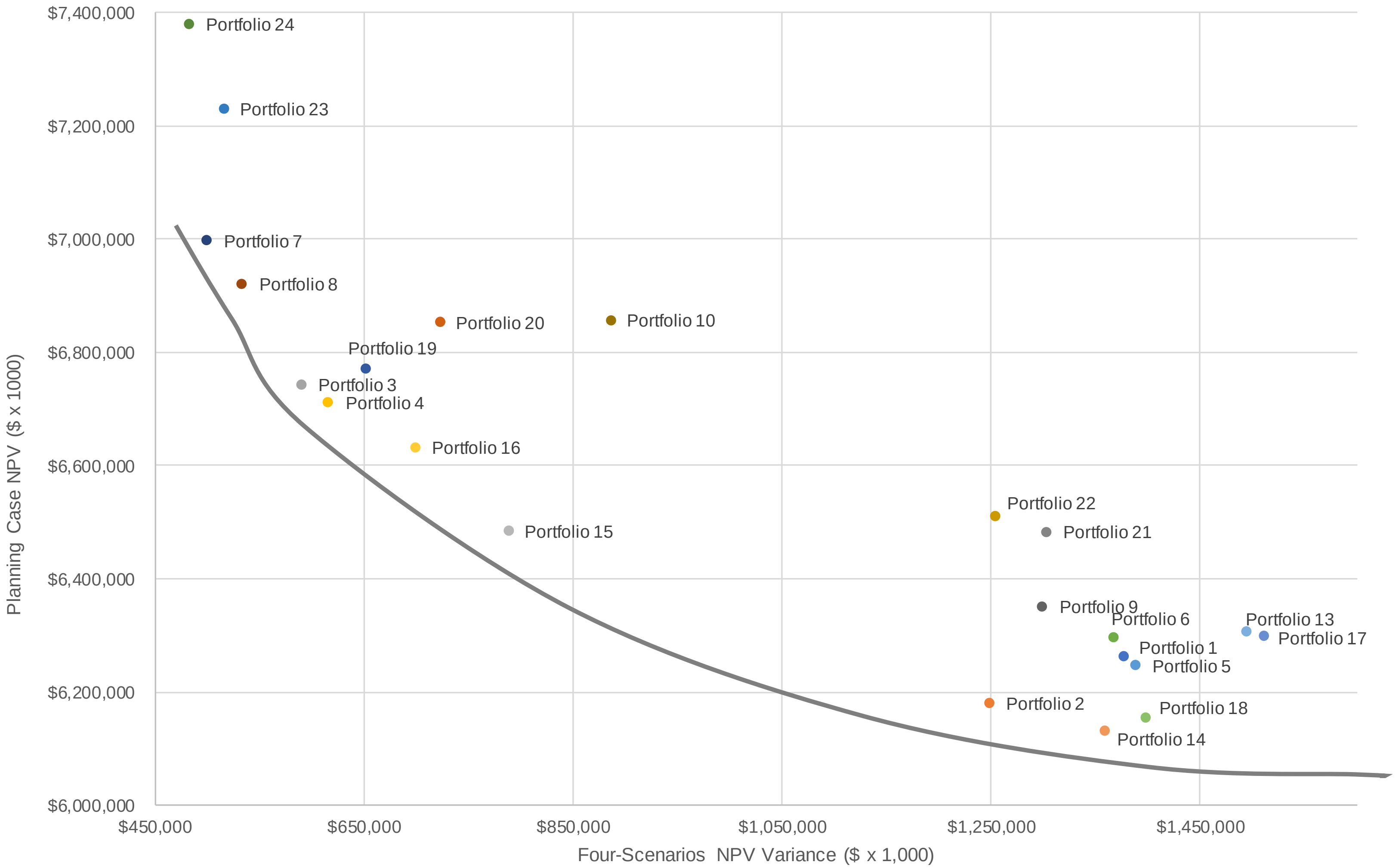
NPV ($ x 1000)	Planning Gas~~—~~, Planning Carbon	High Gas~~—~~, Planning Carbon	Planning Gas~~—~~, High Carbon	High Gas~~—~~, High Carbon
Portfolio 1	$6,~~262,350~~278,713	$~~6,983,921~~7,153,154	$8,~~615,746~~736,678	$9,~~785,216~~802,332
Portfolio 2	$6,~~180,898~~282,756	$7,~~050,988~~174,552	$8,~~268,640~~577,425	$9,~~484,077~~695,929
Portfolio 3	$6,~~743,579~~868,094	$7,~~210,723~~341,418	$~~7,758,806~~8,188,333	$8,~~317,985~~757,756
Portfolio 4	$6,~~711,725~~909,873	$7,~~186,392~~351,820	$~~7,764,683~~8,172,789	$8,~~353,585~~709,946
Portfolio 5	$6,~~247,134~~407,151	$~~6,965,305~~7,051,991	$8,~~640,298~~983,091	$9,~~783,543~~967,976
Portfolio 6	$6,295,~~506~~887	$6,~~991,122~~987,393	$8,~~671,032~~852,891	$9,~~767,701~~853,177
Portfolio 7	$~~6,997,047~~7,230,980	$7,~~335,052~~589,273	$~~7,883,018~~8,284,393	$8,~~298,494~~678,643
Portfolio 8	$~~6,921,411~~7,086,109	$7,~~308,725~~447,426	$~~7,845,686~~8,260,812	$8,~~329,757~~684,372
Portfolio 9	$6,~~351,648~~626,104	$6,~~960,567~~994,787	$8,~~563,652~~645,465	$9,~~640,438~~326,708
Portfolio 10	$6,~~857,192~~866,736	$7,~~075,085~~105,974	$8,~~319,929~~635,942	$9,~~006,307~~196,065
Portfolio 11	$7,~~936,126~~867,263	$7,~~890,594~~897,257	$8,~~512,277~~921,579	$~~8,559,033~~9,057,434
Portfolio 12	$7,~~866,893~~700,882	$7,~~851,159~~866,914	$8,~~408,693~~508,580	$8,~~503,484~~662,707
Portfolio 13	$6,~~298,486~~276,926	$7,~~084,234~~189,464	$8,~~966,855~~839,672	$~~10,126,243~~9,941,809
Portfolio 14	$6,~~131,430~~281,733	$7,~~081,861~~198,597	$8,~~426,982~~715,087	$9,~~721~~879,956
Portfolio 15	$6,~~484,416~~748,522	$7,~~185,644~~487,819	$~~7,780,477~~8,179,919	$~~8,630,057~~9,014,114
Portfolio 16	$6,~~632,764~~674,015	$7,~~205,140~~381,746	$~~7,802,154~~8,062,506	$8,~~516,159~~860,820
Portfolio 17	$6,~~306,492~~339,272	$7,~~084,799~~101,059	$~~8,943,907~~9,025,272	$10,~~093,639~~126,056
Portfolio 18	$6,~~155,638~~371,297	$7,~~057,686~~104,072	$~~8,641,689~~9,012,603	$~~9,775,039~~10,082,271
Portfolio 19	$6,~~770,655~~985,582	$7,~~287,389~~574,547	$~~7,878,895~~8,268,054	$8,~~514,255~~931,658
Portfolio 20	$6,~~852,642~~679,355	$7,~~311,787~~381,868	$8,~~080,079~~051,005	$8,~~740,492~~841,573
Portfolio 21	$6,~~483,530~~472,912	$7,~~074,327~~065,637	$8,~~795,307~~896,703	$9,~~733,627~~815,932
Portfolio 22	$6,~~511,244~~505,881	$7,~~064,598~~071,269	$8,~~722,004~~885,581	$9,~~634,701~~795,651

NPV ($ x 1000)	Planning Gas~~—~~, Planning Carbon	High Gas~~—~~, Planning Carbon	Planning Gas~~—~~, High Carbon	High Gas~~—~~, High Carbon
Portfolio 23	$7,~~230,853~~348,046	$7,~~585,172~~732,620	$8,~~151,311~~633,344	$~~8,574,738~~9,137,650
Portfolio 24	$~~7,380,489~~6,957,458	$7,~~681,075~~665,019	$8,~~228,451~~391,091	$~~8,631,068~~9,237,524

~~Under the Planning Gas and Planning Carbon scenario, P14 has the lowest NPV value of the 24 WECC-optimized portfolios at $6,131,430,000.~~

Figure 9.1 takes the information in Table 9.3 and compares all 24 portfolios on a two-axis graph that shows NPV cost under the planning scenario and the four-scenario standard deviation in NPV costs. The y-axis displays the NPV values under Planning Gas and Planning Carbon, and the x-axis displays the four-scenario standard deviation in NPV costs for the four scenarios shown in Table 9.3. Note that all cost scenarios are given equal weight in determining the four-scenario standard deviation. Idaho Power does not believe that each future has an equal likelihood, but for the sake of simplicity presented the results assuming equal likelihood to provide an idea of the variance in NPV costs associated with the four modeled scenarios.

~~Figure 9.1 shows that P14~~P13 is the lowest-cost portfolio under Planning Gas and Planning Carbon, as can be seen in Figure 9.1 and Table 9.3, although its four-scenario standard deviation is higher than some other portfolios. Conversely, ~~P 24~~P12 has the lowest four-scenario standard deviation, but the second highest expected cost under Planning Gas and Planning Carbon. Portfolios plotted along the lower and left edge of Figure 9.1 represent the efficient frontier in this graph of NPV cost versus cost standard deviation. Moving vertically, portfolios plotting above the efficient frontier are considered to have equivalent cost variance, but higher expected cost. Moving horizontally, portfolios plotting to the right of the efficient frontier are considered to have equivalent expected cost, but greater potential cost variance.



$7,400,000
$7,200,000
$7,000,000
$6,800,000
$6,600,000
$6,400,000
$6,200,000
$6,000,000
Planning Case NPV ($ x 1000)
$450,000
$650,000
$850,000
$1,050,000
$1,250,000
$1,450,000
Four-Scenarios NPV Variance ($ x 1,000)
Portfolio 24
Portfolio 23
Portfolio 7
Portfolio 8
Portfolio 20
Portfolio 10
Portfolio 19
Portfolio 3
Portfolio 4
Portfolio 16
Portfolio 15
Portfolio 22
Portfolio 21
Portfolio 9
Portfolio 6
Portfolio 13
Portfolio 17
Portfolio 1
Portfolio 5
Portfolio 2
Portfolio 18
Portfolio 14

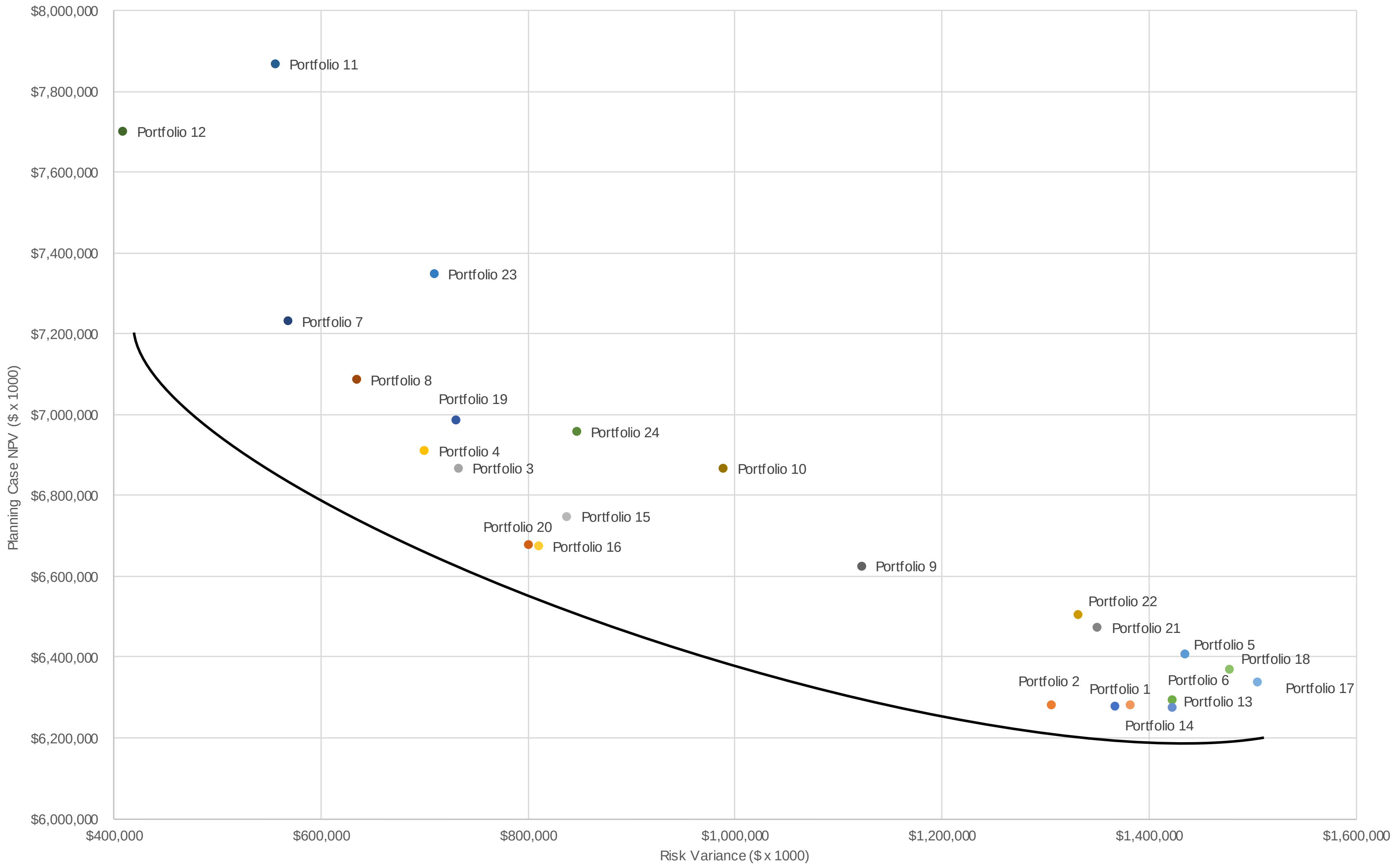


Figure 9.1 NPV cost versus cost variance

~~Based on these results, Idaho Power selected~~As indicated in Table 8.5, the starting point of the manual optimization process was determined from the following ~~four~~ WECC-optimized portfolios ~~for manual adjustment with the objective of further reducing Idaho Power-specific portfolio costs~~:

- ~~Portfolio 2 (~~Planning Gas, Planning Carbon~~, without B2H~~: P(1), P(2), P(13), P(14))
- ~~Portfolio 4 (~~Planning Gas, High Carbon~~, without B2H~~: P(3), P(4), P(15), P(16))
- ~~Portfolio 14 (Planning~~ High Gas, ~~Planning~~High Carbon~~,~~: P(11), P(12), P(23), P(24)

The portfolios identified in the first two categories are close to the line drawn in Figure 9.1 and represent combinations of low cost and low risk. The other points were included in the HGHC category to determine whether a more optimal portfolio could be obtained starting with ~~B2H)~~different flexibility resources (pumped hydro, biomass, and nuclear instead of natural gas).

- ~~Portfolio 16 (Planning Gas, High Carbon, with B2H).~~

Manually Built Portfolios

~~The~~ Manual adjustments ~~to the selected four WECC-optimized portfolios specifically~~ focused first on ~~evaluating~~ the evaluation of Jim Bridger coal unit exit scenarios. In ~~addition, a 15-percent planning margin was preserved while generally retaining~~ the ~~resource mix of the WECC-optimized portfolio. Table 9.4 shows the six selected~~following tables, Jim Bridger exit dates for the first three scenarios ~~studied~~are fixed across the gas and carbon assumptions and provide a comparison of Bridger exit dates. Scenario 1 exits all four units by 2030. Scenario 2 exits the second unit in 2028 but keeps the third and fourth units until 2034. Scenario 3 exits the second unit in 2026 and keeps the third and fourth units until 2034. Scenario 4 exit dates were adjusted differently to further optimize the results. Table 9.4 provides a summary of the Jim Bridger exit scenarios.

Table 9.4 Jim Bridger exit scenarios

Scenario 1	Scenario 2	Scenario 3	Scenario 4
2022	2022	2022	~~2022~~Varied*
2026	2028	2026	~~2026~~Varied*
2028	2034	~~2028~~2034	~~2028~~Varied*
~~2034~~2030	2034	2034	~~2030~~Varied*

* The Jim Bridger exit timing for Scenario 4 was selected based on learnings from the first three scenarios ~~(1), (2), (3),~~ and ~~(4) focused on evaluating exit~~gas and carbon assumptions.

The following guiding principles were used in the manual optimization process for the first three scenarios ~~for the second, third and fourth units,~~:

- The same modeling constraints used within the AURORA modeling software during the WECC optimization were applied to the manual optimization (e.g., Bridger unit exits could not be earlier than the dates identified in Scenario 1)

- The same resource types and approximate resource allocations were used as identified in the WECC-optimized LTCE portfolios
- Resources identified for WECC optimization were deferred and reduced where possible while maintaining a planning margin of 15 percent
- No carbon-emitting resources were added to the high gas, high carbon portfolios

Scenario 4 was completed as an attempt to further refine the results to lower portfolio costs while maintaining a similar level of reliability. The following guiding principles were applied in addition to the ones used for the first three scenarios ~~(5) and (6) focused~~:

- Large-scale CCCT units can in some cases be replaced with more scalable reciprocating gas engines, allowing a phased approach to adding flexible resources which can reduce costs
- Demand response can be accelerated and/or expanded to defer some types of resources
- Depending on ~~evaluating the~~ the portfolio builds, accelerating solar and battery resources and alternating with flexible resources can result in portfolio savings
- Solar plus battery resources were often selected before solar-only resources because they have a higher contribution to peak

The resulting 24 manual builds (six categories with four scenarios each) were evaluated using the AURORA model to determine their NPV using the same gas and carbon pricing forecasts as the initial WECC results shown in Table 9.3. The results of the 24 manual builds are shown in Table 9.5.

As a final step, Valmy Unit 2's exit date ~~associated with the first Jim Bridger unit. Scenarios (~~was accelerated to 2022 as a sensitivity to test the viability of an earlier exit. The final results of the manual build process are shown in Table 9.7.

Table 9.5~~) and (6) centered on portfolios developed under a planning natural gas, planning carbon future, or P2 and P14. Thus, the complete set of~~ 2019 IRP manually built portfolios~~ consists of the following:~~, NPV years 2019–2038 ($ x 1,000)

- ~~P2 derived portfolios—P2(1), P2(2), P2(3), P2(4), P2(5), P2(6)~~
- ~~P4 derived portfolios—P4(1), P4(2), P4(3), P4(4)~~
- ~~P14 derived portfolios—P14(1), P14(2), P14 (3), P14 (4), P14 (5), P14 (6)~~
- ~~P16 derived portfolios—P16(1), P16(2), P16(3), P16(4)~~

~~Manual adjustments yielded the portfolio cost changes for P2 (decreases and increases).~~

~~**Table 9.5 Jim Bridger exit scenario cost changes for P2**~~

~~Scenarios~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~Average~~

NPV ($ x 1000)	Planning Gas, Planning Carbon	~~-0.6%~~High Gas, Planning Carbon	~~-0.8%~~Planning Gas, High Carbon	~~-0.6%~~High Gas, High Carbon
PGPC (1~~.0%~~)	~~2.~~$6~~%~~,279,509	~~2.6%~~$7,426,379	~~1.~~$8~~%~~,233,137	$9,440,332
PGPC (2)	$6,273,071	$7,246,081	$8,490,274	$9,625,390
PGPC (3)	$6,284,277	$7,277,944	$8,431,678	$9,560,285
~~-2.~~PGPC (4~~%~~)	~~-4.~~$6~~%~~,279,772	~~-1.9%~~$7,259,024	~~-5.5%~~$8,558,682	~~-5.3%~~$9,716,348
PGHC (1)	$6,390,311	$7,319,067	$8,032,346	$9,067,148
PGHC (2)	$6,442,048	$7,144,213	$8,264,118	$9,181,798
~~-~~PGHC (3~~.3%~~)	~~-1.~~$6~~%~~,453,111	~~-3.~~$7~~%~~,181,508	~~-3.6%~~$8,242,129	~~-3.0%~~$9,151,410
PGHC (4)	$6,294,814	$7,359,094	$8,091,963	$9,277,557
~~**Average**~~HGHC (1)	~~-0.9%~~$7,469,519	~~-1.~~$7~~%~~,934,725	~~-1.0%~~$8,635,143	~~-1.~~$9~~%~~,153,185
HGHC (2)	$6,987,986	$7,521,331	$8,665,974	$9,374,281
HGHC (3)	$7,043,235	$7,575,393	$8,654,276	$9,326,503
HGHC (4)	$6,855,447	$7,783,286	$8,595,740	$9,639,967
PGPC B2H (1)	$6,239,229	$7,436,314	$8,389,315	$9,634,337
PGPC B2H (2)	$6,267,445	$7,285,695	$8,662,735	$9,863,352
PGPC B2H (3)	$6,267,257	$7,327,131	$8,650,207	$9,858,607
PGPC B2H (4)	$6,247,768	$7,457,533	$8,453,137	$9,705,863
PGHC B2H (1)	$6,342,373	$7,377,938	$8,113,174	$9,290,421
PGHC B2H (2)	$6,326,907	$7,223,445	$8,356,141	$9,518,984
PGHC B2H (3)	$6,325,327	$7,260,956	$8,336,880	$9,508,616
PGHC B2H (4)	$6,231,882	$7,378,575	$8,244,490	$9,576,761
HGHC B2H (1)	$6,627,133	$7,560,819	$8,321,638	$9,377,658
HGHC B2H (2)	$6,551,203	$7,370,092	$8,519,476	$9,591,880
HGHC B2H (3)	$6,549,962	$7,402,601	$8,507,236	$9,581,960
HGHC B2H (4)	$6,505,943	$7,500,370	$8,259,364	$9,394,863

~~As demonstrated in the tables above, the LTCE model performed reasonably well in developing low cost portfolios for Idaho Power's service area. However, Idaho Power was able to further lower overall portfolio costs through the manual refinements detailed above. Based on these results, the company is confident that its preferred portfolio detailed in Chapter 10 achieves the low cost, low risk objective of the IRP.~~

~~Manual adjustments yielded the following portfolio cost changes for P4 (decreases and increases):~~

~~**Table 9.6 Jim Bridger exit scenario cost changes for P4**~~

As discussed previously, tables 9.3 and 9.5 utilized the WECC buildout that each portfolio was designed under, which is shown in figures 8.3 and 8.4. The 24 WECC buildouts are unique in terms of the resources that were selected for each buildout, as well as the timing of each resource.

In order to compare portfolios using the same WECC buildout, the company inserted its manual portfolios into four distinct WECC buildouts: 1) Planning Gas, Planning Carbon; 2) High Gas, Planning Carbon; 3) Planning Gas, High Carbon; 4) High Gas, High Carbon. This comparison allows the company to focus on differences specific to Idaho Power's portfolio design, rather than differences stemming from future WECC buildout scenarios. The results are shown in Table 9.6.

Table 9.6 2019 IRP manually built portfolios, WECC buildout comparison, NPV years 2019–2038 ($ x 1,000)

~~Scenarios~~	~~1~~	~~2~~	~~3~~	~~4~~ ~~Average~~
NPV ($ x 1000)	**Planning Gas, Planning Carbon**	~~-7.9%~~**High Gas, Planning Carbon**	~~-8.2%~~**Planning Gas, High Carbon**	~~-8.1%~~**High Gas, High Carbon**
Portfolio PGPC (1)	$6,279,509	$7,411,931	$8,114,621	$9,345,007
Portfolio PGPC (2)	$6,273,071	$7,236,437	$8,331,134	$9,504,866
Portfolio PGPC (3)	$6,284,277	$7,269,646	$8,292,583	$9,443,642
Portfolio PGPC (4)	$6,279,772	$7,238,655	$8,378,158	$9,552,907
Portfolio PGHC (1)	$6,400,413	$7,334,372	$8,032,346	$9,083,275
Portfolio PGHC (2)	$6,451,515	$7,164,818	$8,264,118	$9,205,845
Portfolio PGHC (3)	$6,462,698	$7,201,220	$8,242,129	$9,176,938
Portfolio PGHC (4)	$6,310,357	$7,363,283	$8,091,963	$9,237,188
~~**High Gas, Planning Carbon**~~Portfolio HGHC (1)	~~-1.~~$7~~%~~,465,092	~~-1.3%~~$7,907,690	~~-2.2%~~$8,603,701	~~-0.4%~~$9,153,185
~~**Planning Gas, High Carbon**~~Portfolio HGHC (2)	~~2.~~$7~~%~~,000,131	~~0.5%~~$7,508,566	~~2.6%~~$8,642,228	~~-0.2%~~$9,374,281
~~**High Gas, High Carbon**~~Portfolio HGHC (3)	$7~~.3%~~,052,572	~~6.~~$7~~%~~,564,816	$8~~.2%~~,632,474	$9,326,503
~~**Average**~~Portfolio HGHC (4)	~~0.~~$6~~%~~,918,876	~~-0.4%~~$7,819,991	~~0.5%~~$8,652,244	~~-0.6%~~$9,639,967

Portfolio PGPC B2H (1)	$6,239,229	$7,392,339	$8,091,379	$9,349,587
Portfolio PGPC B2H (2)	$6,267,445	$7,248,819	$8,357,392	$9,563,648
Portfolio PGPC B2H (3)	$6,267,257	$7,287,162	$8,339,846	$9,557,784
Portfolio PGPC B2H (4)	$6,247,768	$7,401,560	$8,133,197	$9,386,236
Portfolio PGHC B2H (1)	$6,384,339	$7,386,701	$8,113,174	$9,238,667
Portfolio PGHC B2H (2)	$6,360,212	$7,232,682	$8,356,141	$9,460,037
Portfolio PGHC B2H (3)	$6,358,018	$7,270,472	$8,336,880	$9,452,539
Portfolio PGHC B2H (4)	$6,276,172	$7,379,348	$8,244,490	$9,478,369
Portfolio HGHC B2H (1)	$6,688,060	$7,603,598	$8,339,690	$9,377,658
Portfolio HGHC B2H (2)	$6,604,353	$7,410,535	$8,546,168	$9,591,880
Portfolio HGHC B2H (3)	$6,603,227	$7,447,855	$8,528,960	$9,581,960
Portfolio HGHC B2H (4)	$6,582,646	$7,563,134	$8,295,569	$9,394,863

~~Manual adjustments yielded the following~~The WECC buildout approaches provide a measure of how robust each portfolio ~~cost changes~~is under the four futures evaluated.

The best-performing B2H portfolios outperformed the best-performing non-B2H portfolios in the planning case (Planning Gas, Planning Carbon) in both approaches.

Finally, for ~~P14 (decreases~~each of the four future gas and ~~increases):~~carbon scenarios, the company performed a sensitivity analysis to determine the cost, or value, associated with an earlier exit (year-end 2022) of Valmy Unit 2. As noted in the *Nevada Transmission without North Valmy* section of Chapter 6, the Company will be performing a near-term analysis related to Valmy Unit 2 to further investigate market depth and other factors associated with this transmission capacity.

~~**Table 9.7 Jim Bridger exit scenario cost changes for P14**~~

These differentials were then applied to the portfolio costs in Table 9.6 to obtain the results detailed in Table 9.7.

Table 9.7 2019 IRP Manually built portfolios with Valmy exit year-end 2022, NPV years 2019–2038 ($ x 1,000)

~~Scenarios~~ ~~1~~ ~~2~~ ~~3~~ ~~4~~ ~~5~~ ~~6~~ ~~Average~~

NPV ($ x 1000)	Planning Gas, Planning Carbon	~~-0.9%~~High Gas, Planning Carbon	~~-1.3%~~Planning Gas, High Carbon	~~-1.0%~~High Gas, High Carbon
Portfolio PGPC (1)	$6,277,779	$7,421,034	$8,109,662	$9,342,540
Portfolio PGPC (2)	$6,271,341	$7,245,540	$8,326,175	$9,502,399
Portfolio PGPC (3)	$6,282,547	$7,278,749	$8,287,624	$9,441,175
Portfolio PGPC (4)	$6,278,042	$7,247,758	$8,373,199	$9,550,440
Portfolio PGHC (1)	$6,398,683	$7,343,475	$8,027,387	$9,080,808
Portfolio PGHC (2)	$6,449,785	$7,173,921	$8,259,159	$9,203,378
Portfolio PGHC (3)	$6,460,968	$7,210,323	$8,237,170	$9,174,471
Portfolio PGHC (4)	$6,308,627	$7,372,386	$8,087,004	$9,234,721
~~1.0%~~Portfolio HGHC (1)	~~0.~~$7~~%~~,463,362	~~1.~~$7~~%~~,916,793	~~1.7%~~$8,598,742	~~1.6%~~$9,150,718
Portfolio HGHC (2)	$6,998,401	$7,517,669	$8,637,269	$9,371,814
~~Planning Gas, High Carbon~~Portfolio HGHC (3)	~~-1.~~$7~~%~~,050,842		~~-3.~~$8~~%~~,627,515	~~-1.3%~~$9,324,036
~~-0.4%~~Portfolio HGHC (4)	~~-4.5%~~$6,917,146	~~-4.4%~~$7,829,094	~~-4.3%~~$8,647,285	~~-3.0%~~$9,637,500
Portfolio PGPC B2H (1)	$6,236,327	$7,400,616	$8,087,144	$9,346,611
~~Average~~Portfolio PGPC B2H (2)	$6,264,543	~~-0.~~$7~~%~~,257,096	~~-1.~~$8~~%~~,353,157	~~-0.5%~~$9,560,672
Portfolio PGPC B2H (3)	$6,264,355	$7,295,439	$8,335,611	$9,554,808
Portfolio PGPC B2H (4)	$6,244,866	$7,409,837	$8,128,962	$9,383,260
Portfolio PGHC B2H (1)	$6,381,437	$7,394,978	$8,108,939	$9,235,691
Portfolio PGHC B2H (2)	$6,357,310	$7,240,959	$8,351,906	$9,457,061
Portfolio PGHC B2H (3)	$6,355,116	$7,278,749	$8,332,645	$9,449,563
Portfolio PGHC B2H (4)	$6,274,442	$7,388,451	$8,239,531	$9,475,902
Portfolio HGHC B2H (1)	$6,686,330	$7,612,701	$8,334,731	$9,375,191
Portfolio HGHC B2H (2)	$6,602,623	$7,419,638	$8,541,209	$9,589,413
Portfolio HGHC B2H (3)	$6,601,497	$7,456,958	$8,524,001	$9,579,493
Portfolio HGHC B2H (4)	$6,580,916	$7,572,237	$8,290,610	$9,392,396

~~Manual adjustments yielded the following~~The PGPC B2H (1) portfolio ~~cost changes for P16 (decreases and increases):~~

~~**Table 9.8 Jim Bridger exit scenario cost changes for P16**~~

~~Scenarios~~	~~1~~	~~2~~	~~3~~	~~4~~	~~Average~~
~~Planning Gas, Planning Carbon~~	~~-8.5%~~	~~-9.0%~~	~~-8.4%~~	~~-9.6%~~	~~-8.9%~~
~~High Gas, Planning Carbon~~	~~-1.5%~~	~~-1.2%~~	~~-2.0%~~	~~-0.9%~~	~~-1.4%~~
~~Planning Gas, High Carbon~~	~~3.4%~~	~~1.2%~~	~~3.4%~~	~~-0.1%~~	~~2.0%~~
~~High Gas, High Carbon~~	~~10.8%~~	~~8.8%~~	~~11.0%~~	~~7.5%~~	~~9.5%~~
~~Average~~	~~1.1%~~	~~0.0%~~	~~1.0%~~	~~-0.8%~~	~~0.3%~~

~~The costs for~~outperforms the ~~manually built~~other portfolios ~~under~~in the planning case (Planning Gas, Planning Carbon) and ranks high in the ~~four natural gas and carbon scenarios are provided in Table 9.9.~~

~~**Table 9.9 2019 IRP manually built portfolios, NPV years 2019–2038 ($ x 1,000)**~~

~~NPV ($ x 1000)~~	~~Planning Gas—Planning Carbon~~	~~High Gas—Planning Carbon~~	~~Planning Gas—High Carbon~~	~~High Gas—High Carbon~~
~~P2-1~~	~~$6,145,102~~	~~$7,121,558~~	~~$8,074,268~~	~~$9,316,639~~
~~P2-2~~	~~$6,129,872~~	~~$7,182,632~~	~~$7,892,135~~	~~$9,170,679~~
~~P2-3~~	~~$6,143,832~~	~~$7,069,053~~	~~$8,108,875~~	~~$9,330,234~~
~~P2-4~~	~~$6,103,118~~	~~$7,233,055~~	~~$7,816,128~~	~~$9,116,756~~
~~P14-1~~	~~$6,078,583~~	~~$7,153,869~~	~~$8,286,789~~	~~$9,608,551~~
~~P14-2~~	~~$6,050,117~~	~~$7,177,509~~	~~$8,109,147~~	~~$9,404,032~~
~~P14-3~~	~~$6,068,301~~	~~$7,129,172~~	~~$8,319,839~~	~~$9,679,042~~
~~P14-4~~	~~$6,012,329~~	~~$7,201,730~~	~~$7,970,850~~	~~$9,284,089~~
~~P4-1~~	~~$6,182,752~~	~~$7,064,347~~	~~$7,970,468~~	~~$9,134,728~~
~~P4-2~~	~~$6,160,188~~	~~$7,092,252~~	~~$7,801,005~~	~~$8,964,360~~
~~P4-3~~	~~$6,170,775~~	~~$7,025,150~~	~~$7,968,725~~	~~$9,154,217~~
~~P4-4~~	~~$6,151,167~~	~~$7,155,210~~	~~$7,751,893~~	~~$8,913,303~~
~~P16-1~~	~~$6,069,778~~	~~$7,095,243~~	~~$8,068,014~~	~~$9,437,687~~
~~P16-2~~	~~$6,033,966~~	~~$7,117,922~~	~~$7,896,872~~	~~$9,268,367~~
~~P16-3~~	~~$6,076,723~~	~~$7,063,064~~	~~$8,065,497~~	~~$9,451,679~~
~~P16-4~~	~~$5,996,478~~	~~$7,143,613~~	~~$7,791,783~~	~~$9,152,575~~
~~P2-5~~	~~$6,117,622~~	~~$7,233,779~~	~~$7,827,998~~	~~$9,129,774~~
~~P2-6~~	~~$6,129,786~~	~~$7,230,697~~	~~$7,840,382~~	~~$9,139,164~~
~~P14-5~~	~~$6,026,339~~	~~$7,200,864~~	~~$7,985,612~~	~~$9,291,816~~
~~P14-6~~	~~$6,040,012~~	~~$7,198,508~~	~~$7,999,308~~	~~$9,302,299~~

~~Under~~Planning Gas, High Carbon case. Based on these results, the ~~Planning Gas and Planning Carbon scenario, P16(4) has~~company is confident that the ~~lowest NPV value~~Preferred Portfolio detailed in Chapter 10 achieves the least-cost, least-risk objective of the ~~24 WECC-optimized portfolios at $5,996,478,000~~IRP.

Stochastic Risk Analysis

The stochastic 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 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.

Idaho Power identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Natural gas prices follow a log-normal distribution adjusted upward from the planning case gas price forecast, which is shown as the dashed line in Figure 9.2. Natural gas prices are adjusted upward from the planning case to capture upward risk in natural gas prices. The correlation factor used for the year-to-year variability is 0.65, which is based on historic values from 1997 through 2018.

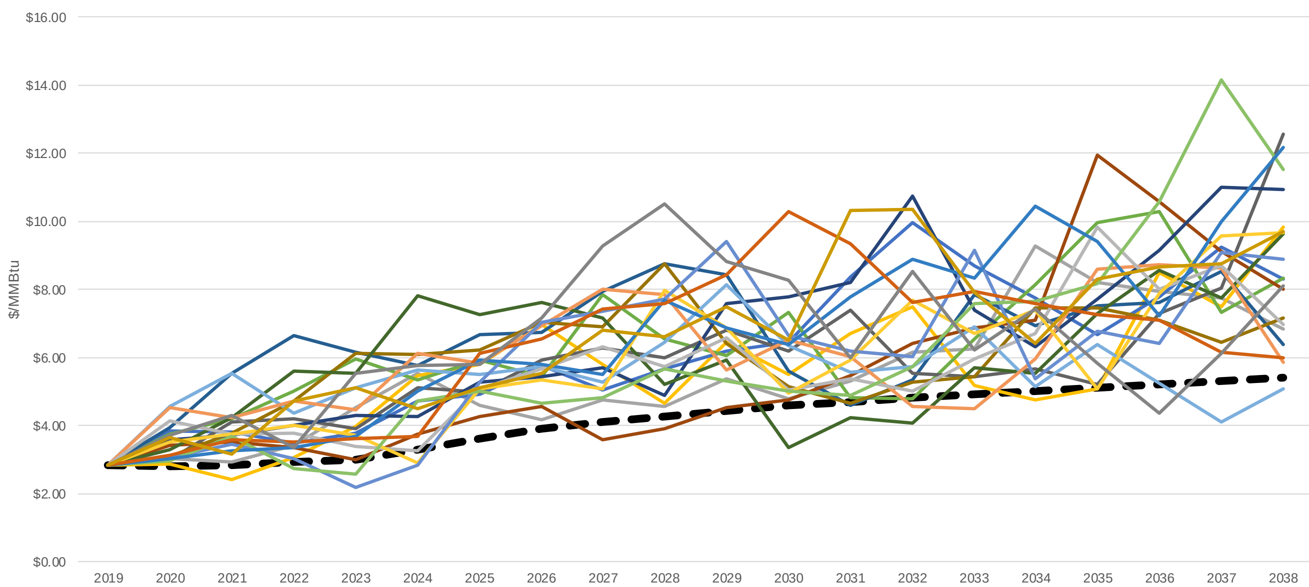


Figure 9.2 Natural gas sampling (Nominal $/MMBtu)

2. *Customer load*—Customer load follows a normal distribution and is adjusted around the planning case load forecast, which is shown as the dashed line in Figure 9.3

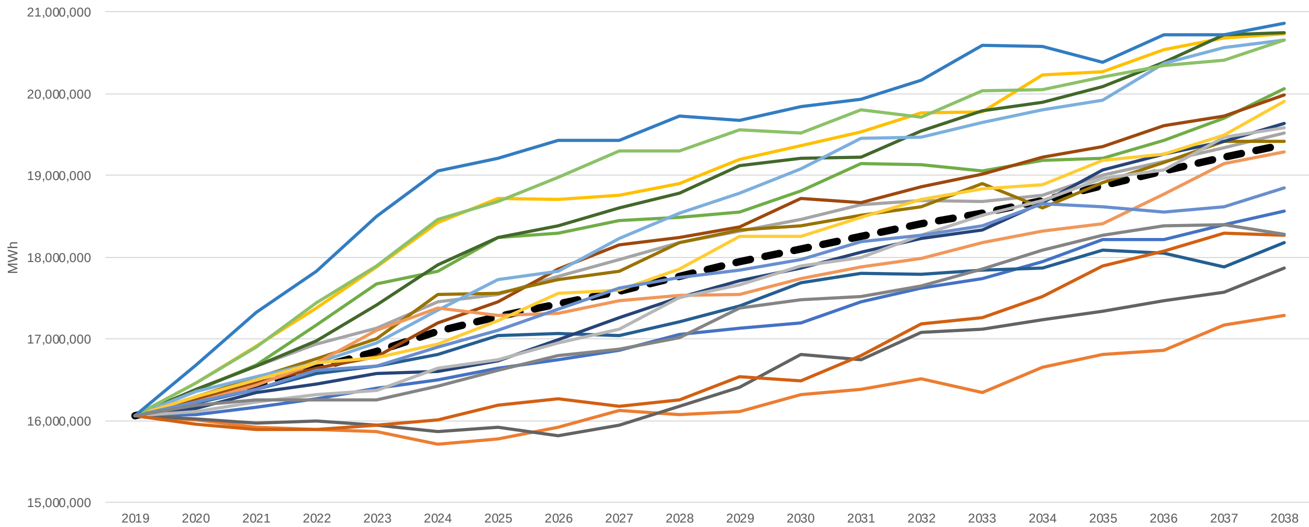


Figure 9.3 Customer load sampling (annual MWh)

3. *Hydroelectric variability*—Hydroelectric variability follows a log-normal distribution and is adjusted around the planning case hydroelectric generation forecast, which is shown as the black dashed line in Figure 9.4. The correlation factor used for the year-to-year variability is 0.80, which is based on historic values from 1971 through 2018.

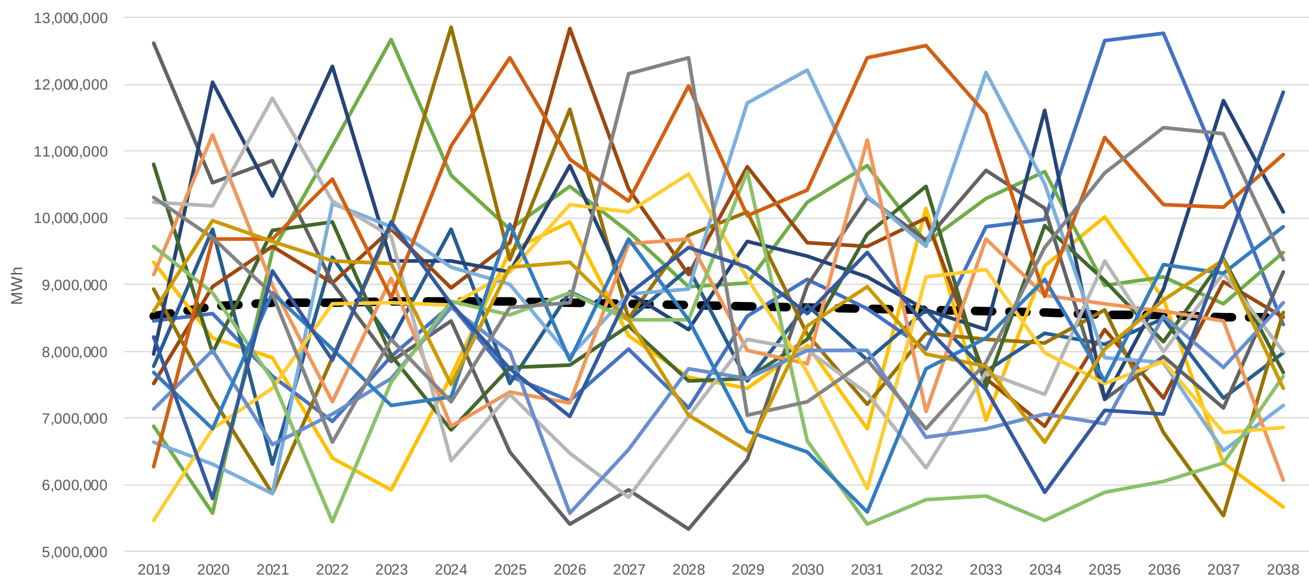


Figure 9.4 Hydro generation sampling (annual MWh)

The three selected stochastic variables are key drivers of variability in year-to-year power-supply costs and therefore provide suitable stochastic shocks to allow differentiated results for analysis.

Idaho Power created a set of 20 iterations based on the three stochastic variables (hydro condition, load, and natural gas price). The 20 iterations were developed using a Latin

Hypercube sampling rather than Monte Carlo. The Latin Hypercube design samples the distribution range with a relatively smaller sample size, allowing a reduction in simulation run times. Idaho Power then calculated the 20-year NPV portfolio cost for each of the 20 iterations for all 24 portfolios. The distribution of 20-year NPV portfolio costs for all 24 portfolios is shown in Figure 9.5.

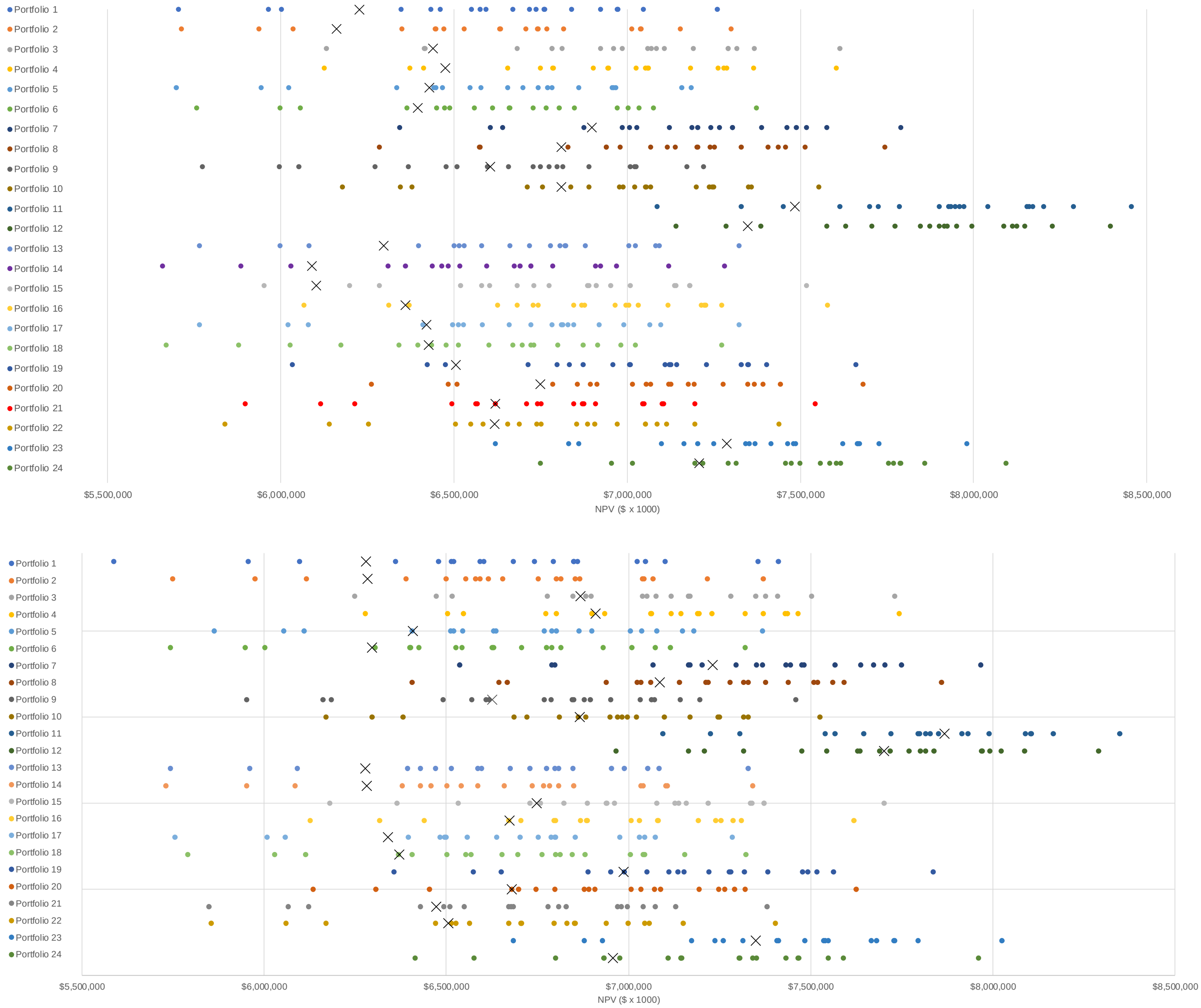
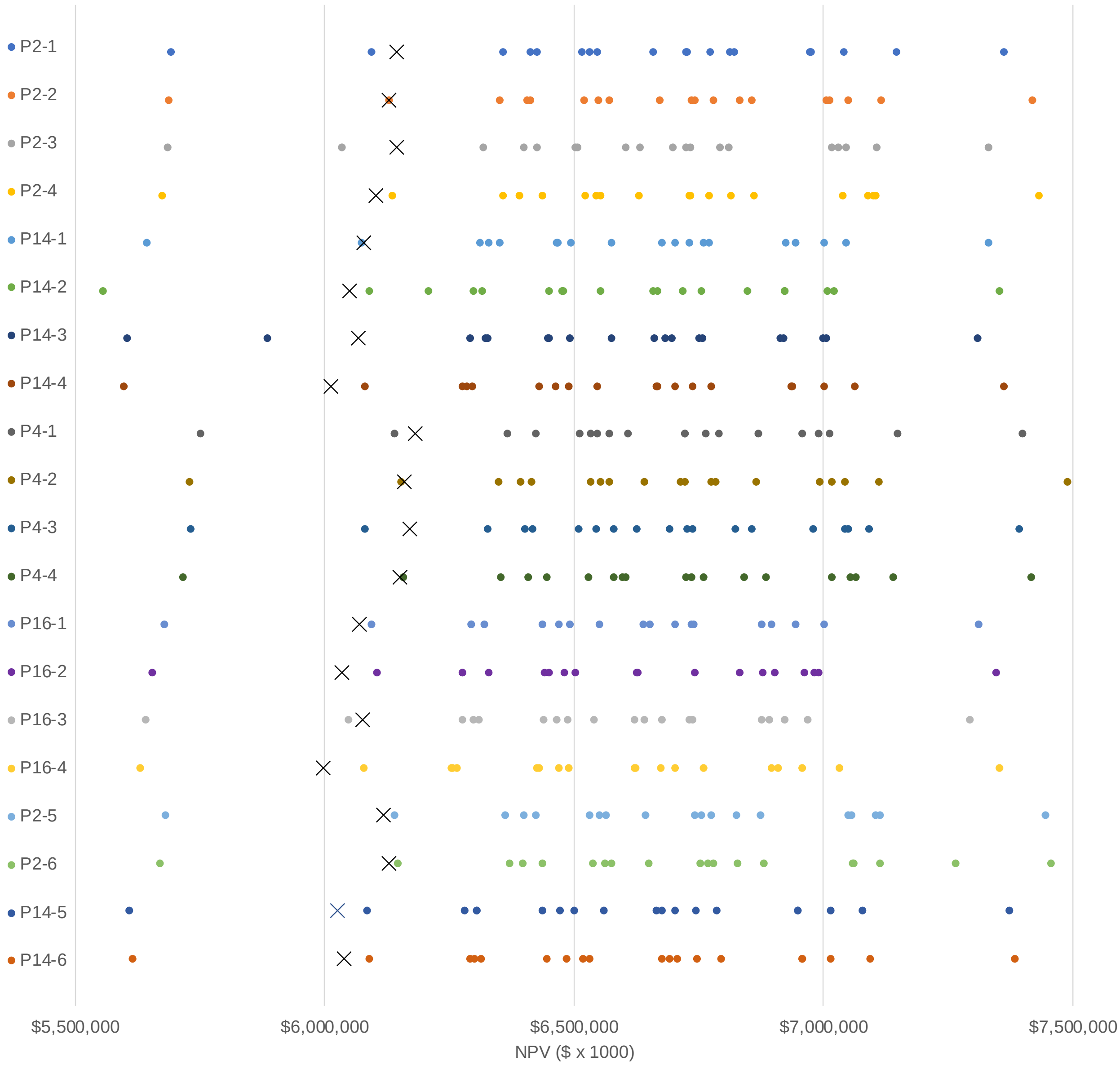


Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2019–2038 ($x 1,000)

The horizontal axis on Figure 9.5 represents the portfolio cost (NPV) in millions of dollars, and the 24 portfolios are represented by their designation on the vertical axis. Each portfolio has 20 dots for the 20 different stochastic iterations scattered across different NPV ranges. The Xs designate the Planning Gas Planning Carbon scenario that was performed for each portfolio.

The distribution of 20-year NPV portfolio costs for the set of 20 manually built portfolios is shown in Figure 9.6.


P2-1
P2-2
P2-3
P2-4
P14-1
P14-2
P14-3
P14-4
P4-1
P4-2
P4-3
P4-4
P16-1
P16-2
P16-3
P16-4
P2-5
P2-6
P14-5
P14-6
$5,500,000
$6,000,000
$6,500,000
$7,000,000
$7,500,000
NPV ($ x 1000)

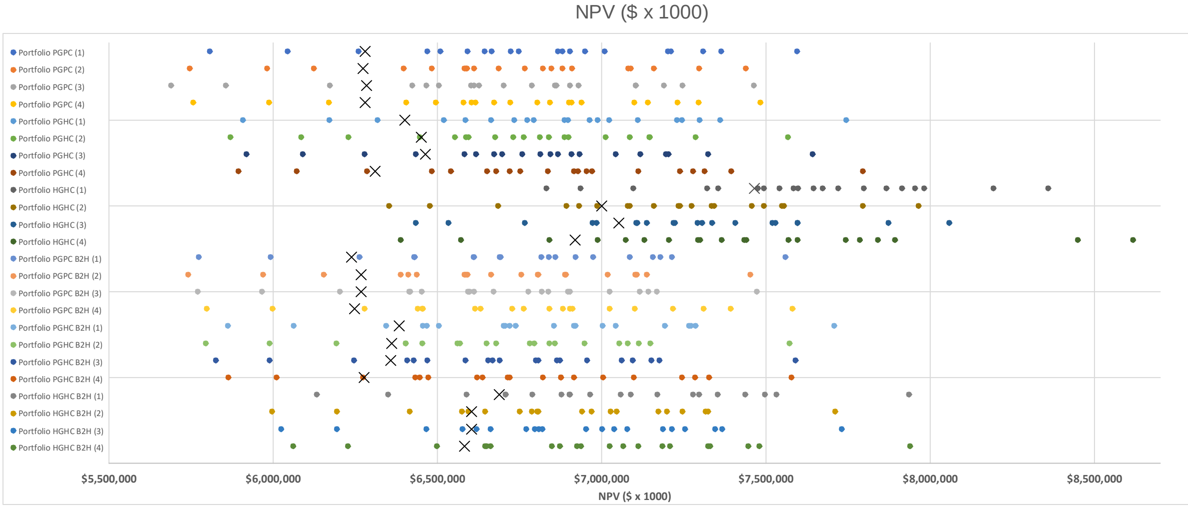
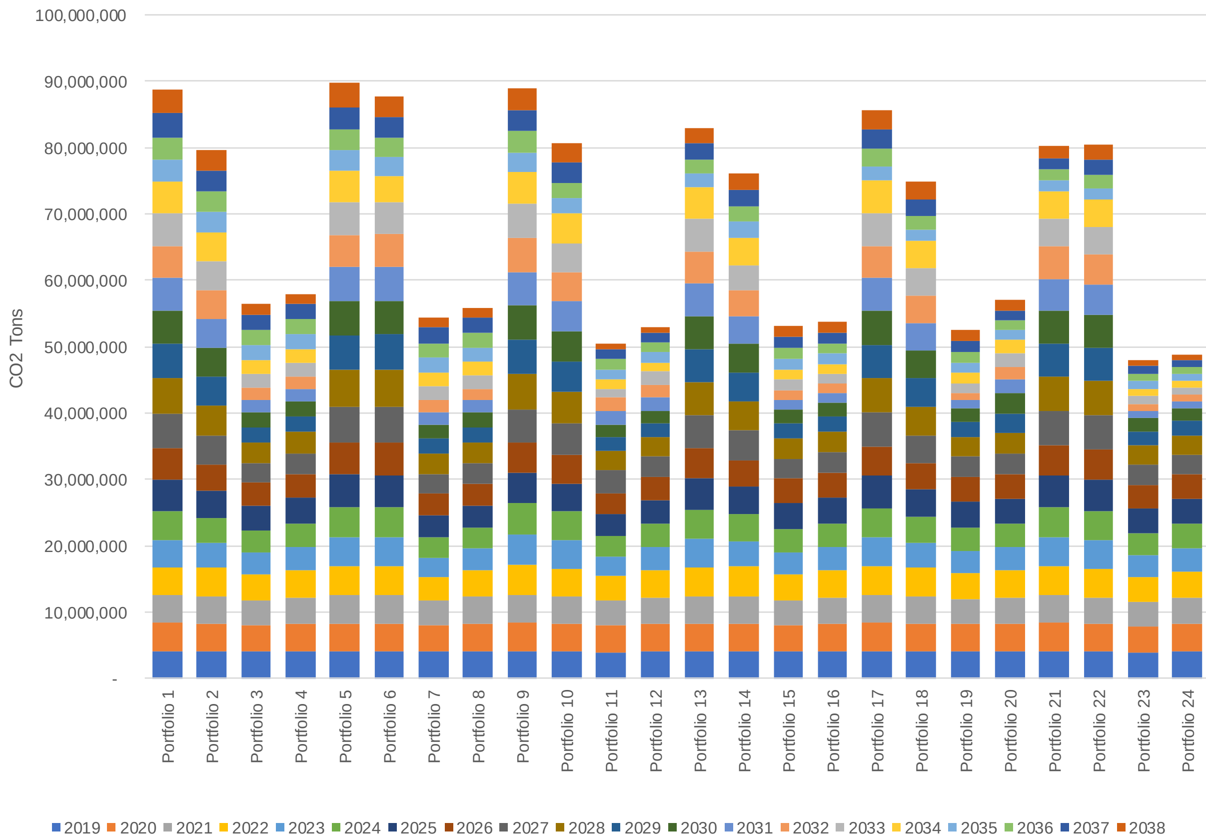

Portfolio PGPC (1)
Portfolio PGPC (2)
Portfolio PGPC (3)
Portfolio PGPC (4)
Portfolio PGHC (1)
Portfolio PGHC (2)
Portfolio PGHC (3)
Portfolio PGHC (4)
Portfolio HGHC (1)
Portfolio HGHC (2)
Portfolio HGHC (3)
Portfolio HGHC (4)
Portfolio PGPC B2H (1)
Portfolio PGPC B2H (2)
Portfolio PGPC B2H (3)
Portfolio PGPC B2H (4)
Portfolio PGHC B2H (1)
Portfolio PGHC B2H (2)
Portfolio PGHC B2H (3)
Portfolio PGHC B2H (4)
Portfolio HGHC B2H (1)
Portfolio HGHC B2H (2)
Portfolio HGHC B2H (3)
Portfolio HGHC B2H (4)
$5,500,000
$6,000,000
$6,500,000
$7,000,000
$7,500,000
$8,000,000
$8,500,000
NPV ($ x 1000)

Figure 9.6 Manually built portfolio stochastic analysis with Valmy exit year-end 2022, total portfolio cost, NPV years 2019–2038 ($x 1,000)

The stochastic risk analysis, coupled with the portfolio cost analysis, assesses the portfolios' relative exposure to significant cost drivers. The wide range of resulting portfolio costs evident in Table 9.~~3~~7 and Figure 9.~~5~~6 reflects the wide range of considered conditions for the cost drivers. The widely ranging costs are an indication that portfolio exposure to cost drivers is sufficiently evaluated. Further, the stochastic analysis suggests that changes in strong cost drivers do not shift the relative cost difference between portfolios significantly and thus does not favor one portfolio over another.

Portfolio Emission Results

~~The~~ CO_2 emissions for all 24 portfolios were evaluated during the portfolio cost analysis. The results for all 24 portfolios ~~is~~are shown in Figure 9.~~6~~7. Figure 9.~~6~~7 is a stacked column that shows the year-to-year cumulative emissions for each portfolio's projected generating resources.



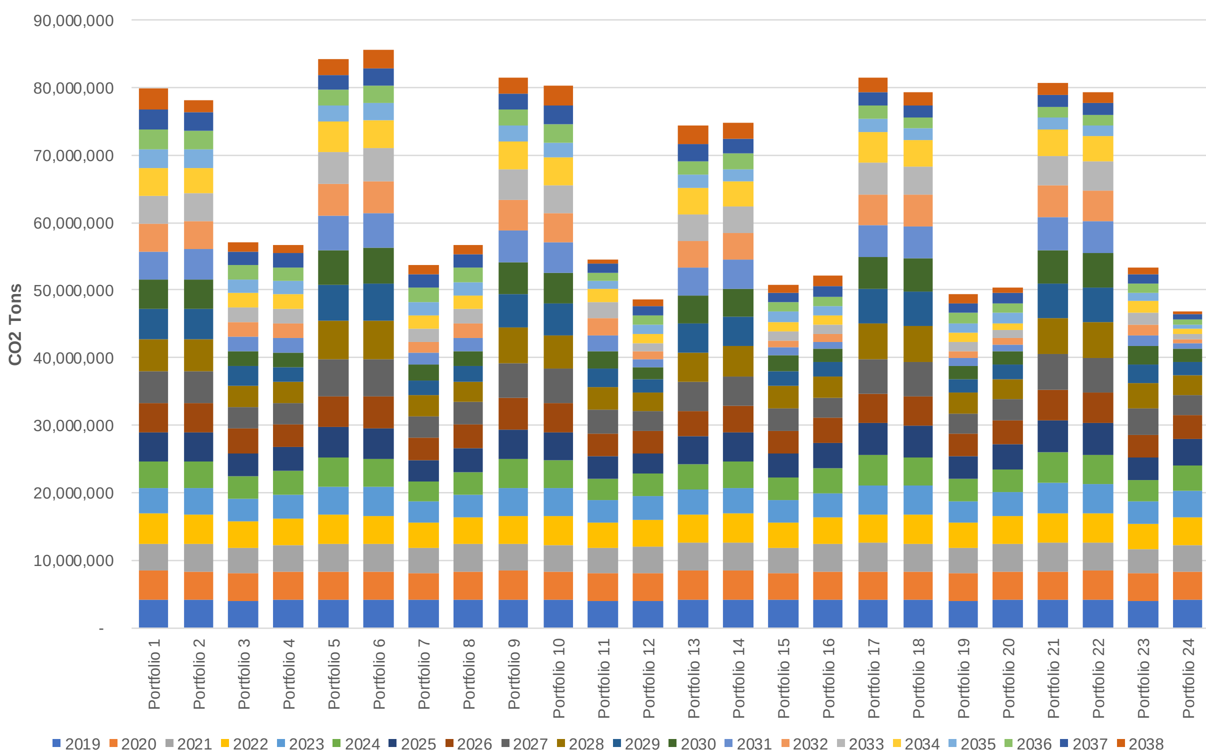
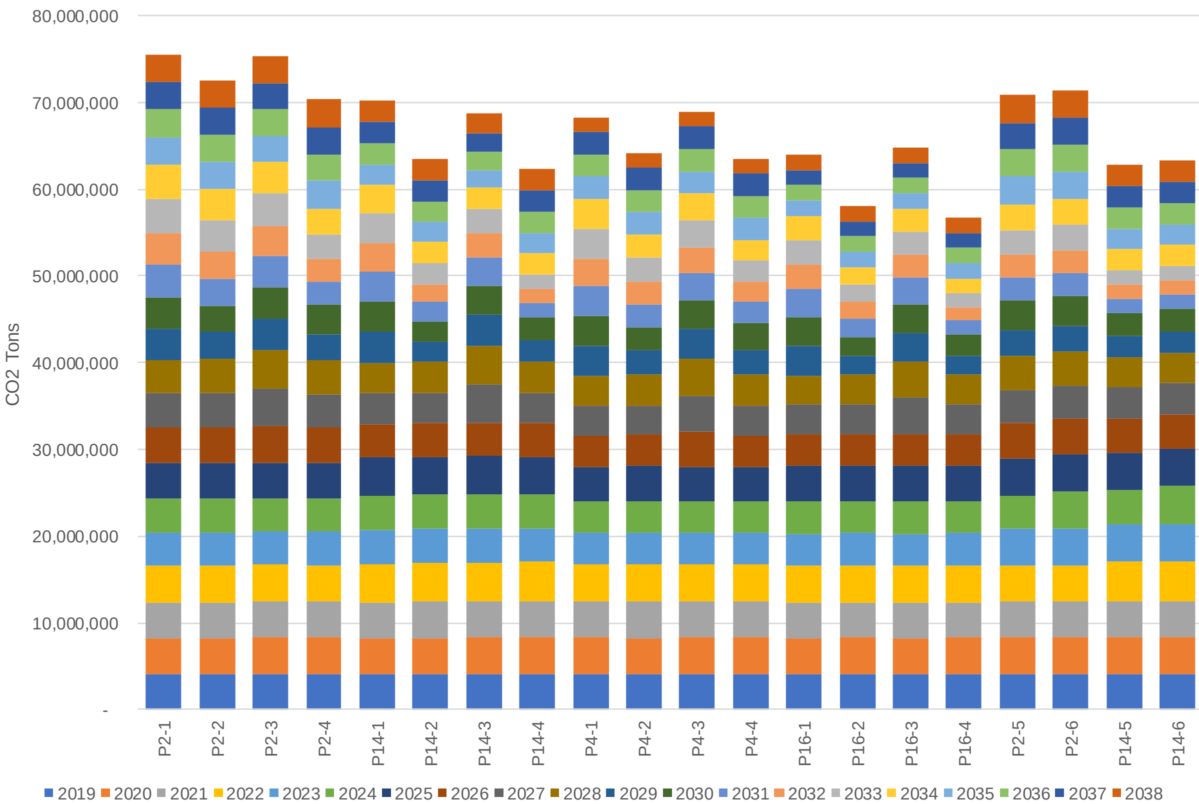


Figure 9.7 Estimated portfolio emissions from 2019–2038



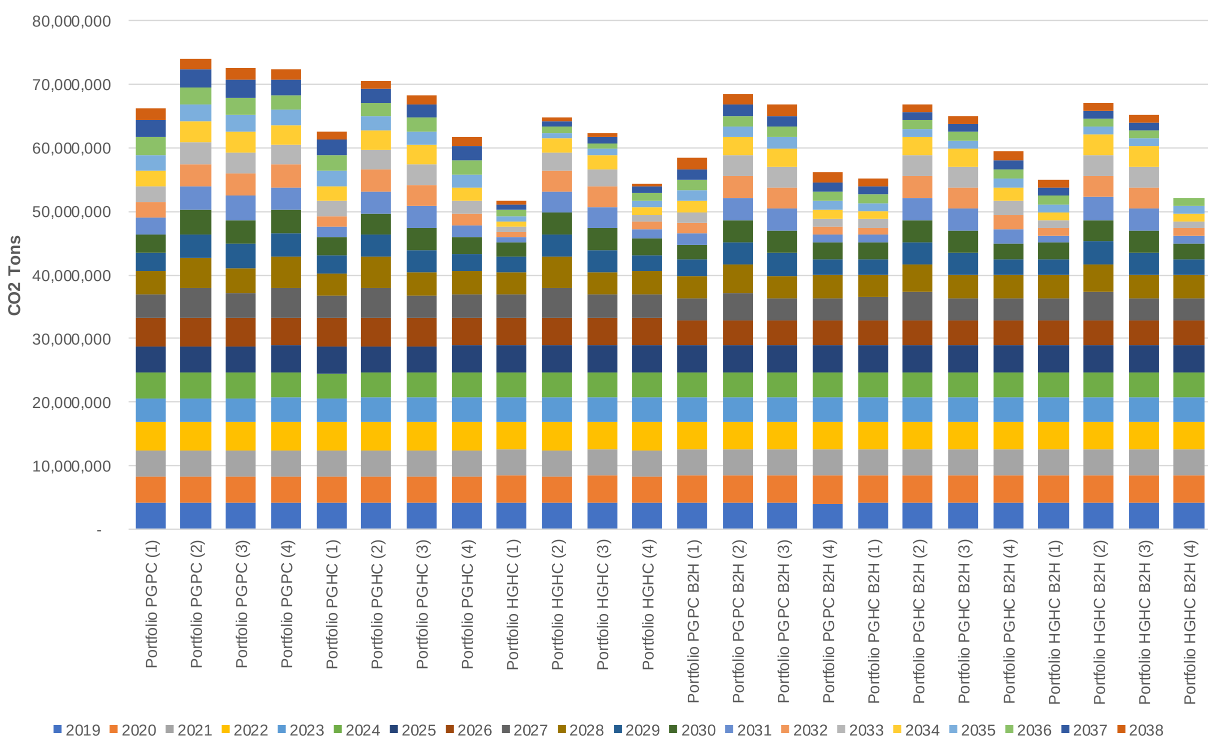


Figure 9.8 Estimated portfolio emissions from 2019–2038—manually built portfolios

Qualitative Risk Analysis

Major Qualitative Risks

- *Fuel Supply*—All generating and transmission resources require a supply of fuel to provide electricity. The 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 infrastructure to produce and transport fuel by rail or pipeline and include mining or drilling facilities. Infrastructure has several risks when evaluating resources. Infrastructure is susceptible to outages from weather, mechanical failures, labor unrest, etc. Infrastructure can be limited in its existing availability to increase delivery of fuel to a geographic area that limits the amount of a 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 and coal 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.

- *Siting and Permitting*—All generating and transmission resources in the portfolios require siting and permitting for the resource to be successfully developed. The 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 siting impacts have a higher risk. These include natural gas, nuclear, pumped storage and transmission resources, as well as solar and wind if the projects or associated transmission lines are sited on federal lands.

- *Technological Obsolescence*—Innovation in future generating resources may possess lower costs of power and have more desirable characteristics. Current technologies may become noncompetitive and strand investments which may adversely impact customers economically. Energy efficiency and demand response have the lowest exposure to technological obsolescence.

- *JB NOx Compliance Alternatives*—The negotiation with the Wyoming DEQ to extend the utilization of Jim Bridger units 1 and 2 without SCR investments to comply with the *Federal Clean Air Act* Regional Haze rules has not been completed. Without alternative compliance dates, these units have a risk of not being available for use in a portfolio after 2021 and 2022. Future reliance on these units may adversely impact customers and system reliability if a timely settlement is not obtained.

- *Partnerships*—Idaho Power is a partner in coal facilities and is currently jointly permitting and siting transmission facilities in anticipation of partner participation in construction and ownership of these transmission 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. B2H and Jim Bridger early unit retirement portfolios have the highest partner risk.

- *Federal and State Regulatory and Legislative*—There are currently 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.

- *Resource Off-Ramp Risks*—All resources require time to successfully approve, permit, site, engineer, procure, and build. Some resources have long development lead times incurring costs along the way, while others have relatively short lead times with much lower development costs. As previously mentioned, the pace of change in the power industry and electric markets is increasing. Consequently, resources that have a compelling story today may be less attractive in a not-so-distant future. The flexibility to not construct a resource when forecasted conditions change is an important consideration. Resources with long lead times and high development costs are susceptible to off-ramp risk. Likewise, early retirement and decommissioning of units ~~limit~~limits flexibility to include the resource in the future. Reducing optionality in the selection of future resources may adversely affect customers economically.

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 in light of potential bad outcome for each resource and the portfolio of resources as a whole. Idaho Power evaluated each resource and resource portfolio against the qualitative risk components as described in the preceding section on the selection of the preferred portfolio.

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 requires a system to have dispatchable resources available at all times to maintain reliability and to comply with FERC rules and California Independent System Operator (CAISO) 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 increases the reliance on baseload thermal resources like the Jim 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.

Frequency Duration Loss of Load Evaluation

Idaho Power used AURORA to evaluate the system loss of load using a frequency duration outage methodology for the 2019 IRP. The preferred portfolio was selected and analyzed in AURORA for 100 iterations in the year 2025. The year 2025 was selected because Idaho Power believes it will be a pivotal year. For the preferred portfolio, in 2025, there is not a large amount of excess resources on the system; the last resource built will have been a solar facility in 2023 and 2025 is a year before B2H going into service. The AURORA setup consists of generation resources and their associated forced (unexpected) outage rates. Given these outage rates, the model randomly allowed units to fail or return to service at any time during the simulation. The units selected for random outages were hydro units in the HCC, existing coal units on-line during 2025, and existing natural gas units. The setup also allowed transmission import lines to fail during the peak month of the study. The hydro generation was modified from the planning case 50 percent exceedance level to a more water restrictive 90 percent exceedance level. The demand forecast was also modified from the 50th percentile forecast to a higher load forecast of 95th percentile.

Ultimately, ~~six~~four unique loss-of-load events occurred out of the 100 iterations of year 2025. The results of the loss-of-load analysis show Idaho Power's system ~~will exceed~~performing within the industry standard of less than one event per 10 years and will be resource adequate through ~~2025, the year prior to the next major resource addition~~the planning timeframe.

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 reduce 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 2019 IRP, Idaho Power reviewed two recent assessments with characterizations of regional resource adequacy in the Pacific Northwest: The *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the NWPCC Resource Adequacy Advisory Committee (RAAC); and 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 NWPCC RAAC uses a loss-of-load probability (LOLP) of 5 percent as a metric for assessing resource adequacy. The analytical information generated by each resource adequacy assessment is used by regional utilities in their individual IRPs.

The RAAC issued the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report on June 14, 2018,[25] which reports the LOLP starting in operating year 2021 will exceed the acceptable 5 percent threshold and remain above through operating year 2023. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 MW in 2021 with an additional need for 300 to 400 MW in 2022. The RAAC assessment includes all projected regional resource retirements and energy efficiency savings from code and federal standard changes but does not include approximately 1,340 MW of planned new resources that are not sited and licensed, and approximately 400 MW of projected demand response.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent results in an LOLP of under 5 percent.

From Idaho Power's standpoint, even with the conservative assumptions adopted in the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report, the LOLP is zero for the critical summer months (see Figure 9.~~7~~9). The NWPCC analysis indicates that the region has a surplus in the summer; this is the reason that B2H works so well as a resource in Idaho Power's IRP.

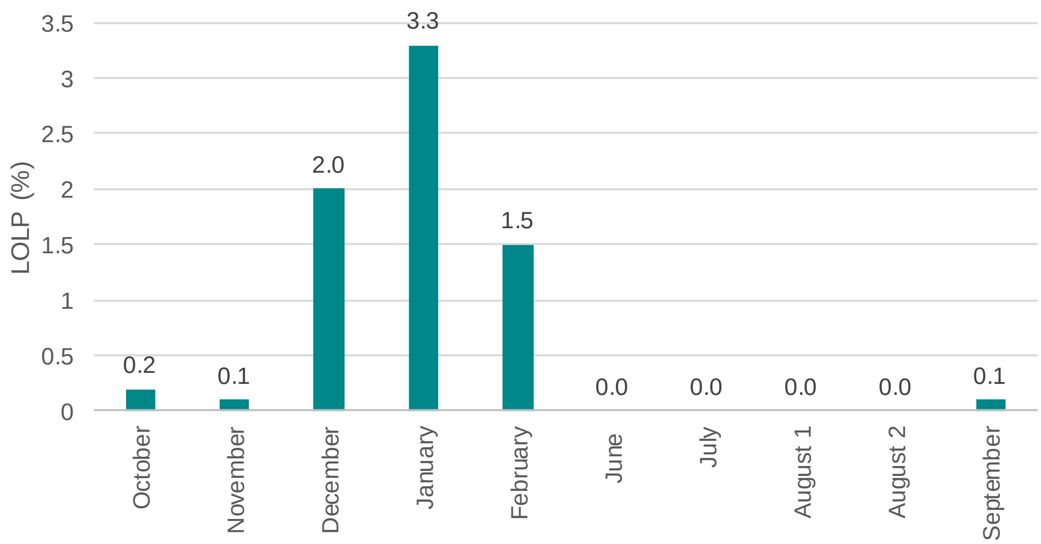


Figure 9.9 LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[26] 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

[25] NWPCC. Pacific Northwest power supply adequacy assessment for 2023. Document 2018-7. nwcouncil.org/sites/default/files/2018-7.pdf. Accessed April 25, 2017.

[26] BPA. 2018 Pacific Northwest loads and resources study (2018 white book). Technical Appendix, Volume 2: Capacity Analysis. bpa.gov/p/Generation/White-Book/wb/2018-WBK-Technical-Appendix-Volume-2-Capacity-Analysis-20190403.pdf. Accessed June 20, 2019

included when those resources begin operating or are under construction and have a scheduled on-line 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 9.~~10~~8 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

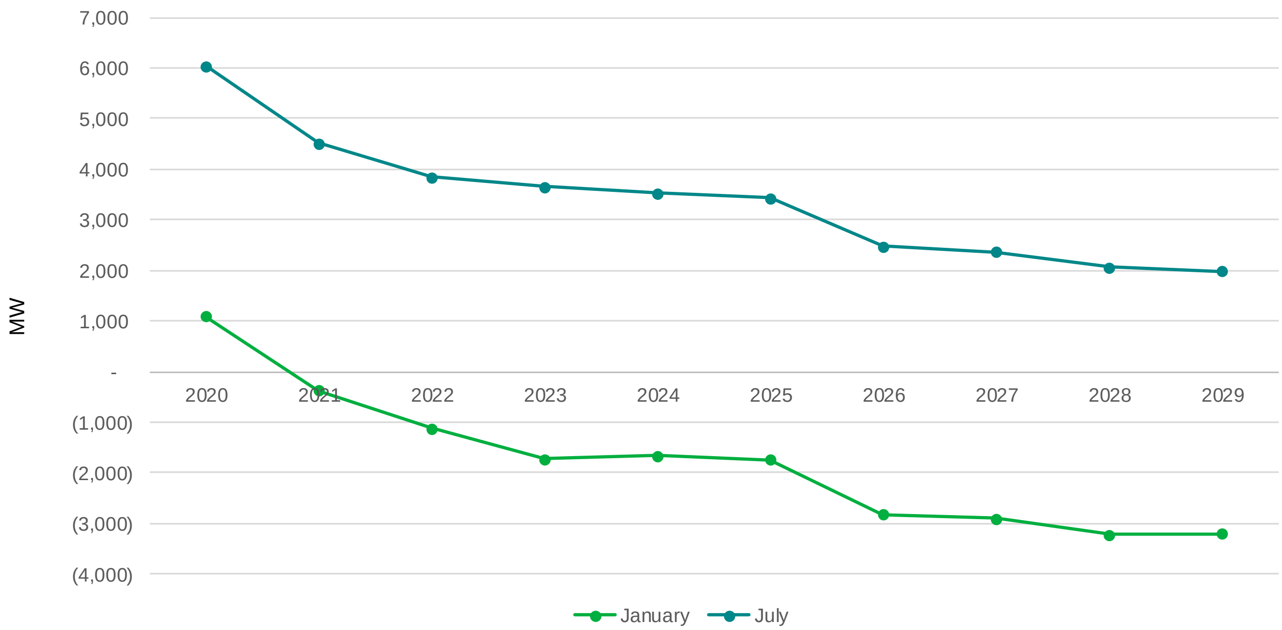


Figure 9.10 BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Finally, 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 9.~~9~~11.

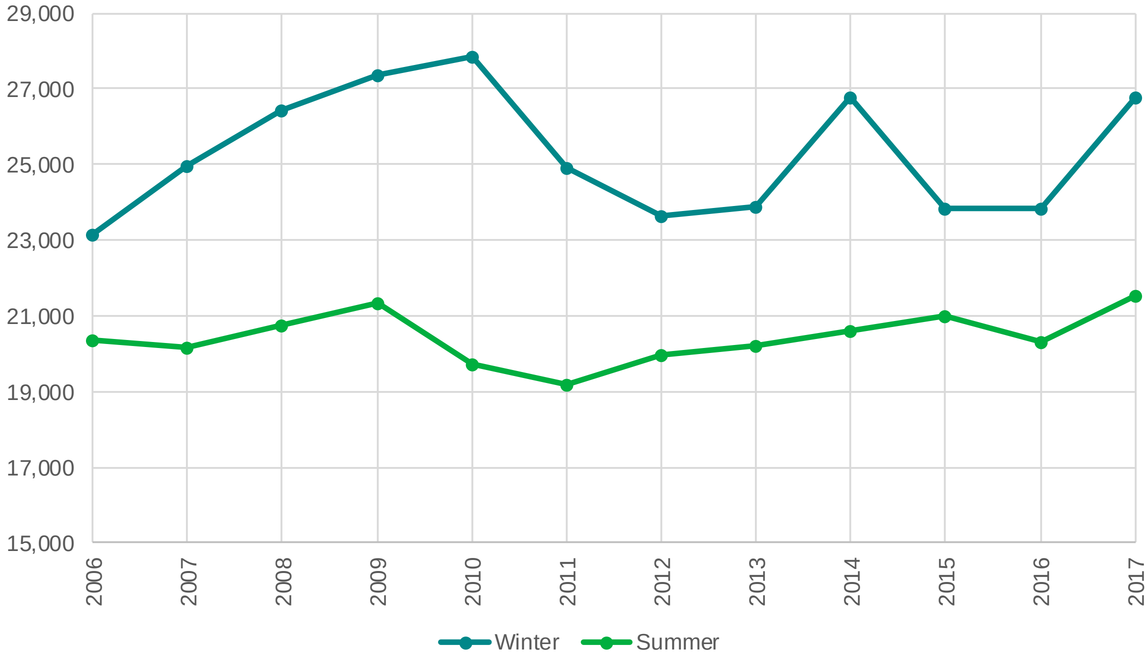


Figure 9.11 Peak coincident load data for most major Washington and Oregon utilities

Figure 9.~~9~~11 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area in the region. Other considerations, not depicted, include Canada's similar winter- to summer-peak load ratio, and 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.

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 intermittent renewable resources.

10. Preferred Portfolio and Action Plan

Preferred Portfolio

The portfolio development process for Idaho Power's *Second Amended 2019 IRP* evolved from a completely manual portfolio development process in past IRPs to using ~~AURORA's~~the LTCE capability for the first time for the 2019 IRP. The 24 resource portfolios developed are substantially different in their resource composition, driven by assumed future conditions for natural gas price and carbon cost. Once resource portfolios were generated, cost analysis for the 24 resource portfolios was performed under four different assumptions: planning case conditions for natural gas price and carbon cost, and also under higher-cost futures as shown in Table 10.1.

Table 10.1 AURORA hourly simulations

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

The cost evaluation for different futures can be considered an examination of the quantitative risk associated with the higher-cost futures for natural gas and carbon prices, particularly on resource portfolios developed by AURORA assuming planning case conditions for natural gas price and carbon. The company also performed a stochastic risk analysis on the 24 resource portfolios, in which portfolio costs were computed for 20 different iterations for the studied stochastic risk variables: natural gas price, hydroelectric production, and system load. Collectively, between the portfolio cost evaluation under different natural gas/carbon cost assumptions and the numerous stochastic runs, risk is quantitatively captured over a wide range of potential futures.

To ensure the AURORA-produced WECC-optimized portfolios are aligned with the company's purpose of providing customers reliable and affordable energy, a subset of top-performing WECC portfolios ~~was~~were joined into categories and then manually adjusted with the objective of further reducing portfolio costs specific to the Idaho Power system. The selected Preferred Portfolio for the *Second Amended 2019 IRP* ~~is a derivative of WECC-optimized portfolio P16, a portfolio~~was developed under an assumption of planning case natural gas ~~price forecast and high case~~and carbon ~~cost forecast. The preferred portfolio from~~ price forecasts. In terms of nomenclature, the ~~2019 IRP~~Preferred Portfolio is designated as ~~P16(4~~Portfolio PGPC B2H (1), where the modifying numeral ~~4~~1 represents the ~~Jim Bridger exit~~ first scenario identified in Table 9.4 (exit from Bridger coal units in 2022, 2026, 2028, and 2030). ~~The preferred portfolio was further evaluated under an assumption of planning case natural gas price forecast and planning case carbon cost forecast, represented by P14(7).~~

Adjustments to ~~P16 yielding~~ the Preferred Portfolio are ~~largely related to timing of resource actions, primarily~~described in ~~delaying~~ the ~~WECC-optimized portfolio's expansion of wind and solar resources in the 2020s. With the exception of wind resources, which declined by 300 MW nameplate over the IRP time horizon, the total nameplate capacity by resource type in the WECC-optimized portfolio is similar in quantity to its manually adjusted version.~~Manually Built

Portfolios section of Chapter 8. The Preferred Portfolio, particularly with the expansion of ~~wind~~solar and ~~solar~~storage resources in the 2030s, is considered to align well with Idaho Power's goal of 100 percent clean energy by 2045.

Resource actions of the Preferred Portfolio are provided in Table 10.2.

Table 10.2 Preferred Portfolio additions and coal exits (MW)

	Gas	Solar	Battery	Demand Response	Coal Exit
2019					-127 (Valmy)
2020					-58 (Boardman)
2021					
2022		120			-177 -133 (Bridger, Valmy*)
2023					
2024					
2025					
2026					-180 (Bridger)
2027					
2028					-174 (Bridger)
2029			~~40~~	~~30~~	
2030	~~300~~	40	30	5	-177 (Bridger)
2031	300			5	
2032			~~80~~	5	
2033			~~80~~	5	
2034		40	20	5	
2035	~~111~~	80	20	5	
2036		120	10	5	
2037	55.5		~~320~~	5	
2038	55.5	~~300~~	~~440~~	5	
Nameplate Total	**411**	**~~300~~400**	**80**	**~~30~~45**	**-1,026**
B2H (2026)	500				

* Idaho Power has identified the potential for additional savings from an exit date as early as 2022. Further analysis must to conducted to determine optimal exit timing that weighs economics and system reliability. More detail on this study is provided in the Valmy Unit 2 Exit Date section of Chapter 1 of this document.

Action Plan (~~2019~~2020–2026)

The *Second Amended* *2019 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, 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 recently announced goal of 100 percent clean energy by 2045 make the 2019 action plan especially germane.

The resource additions and coal exits identified in the Action Plan window have not changed compared to the *Amended 2019 IRP*, with the possible exception of the exit date for Valmy Unit 2. More detail on this study is provided in the Valmy Unit 2 Exit Date section of Chapter 1 of this document.

The Action Plan associated with the Preferred Portfolio is driven by its core resource actions through the mid-2020s. These core resource actions include:

- 120 MW of added solar PV capacity (2022)
- Exit from ~~three~~four coal-fired generating units by year-end 2022, and from five coal-fired generating units (total) by year-end 2026
- B2H on-line in 2026

The Action Plan is heavily influenced by the above resource actions and portfolio attributes, which are discussed briefly in the following sections.

120 MW Solar PV Capacity (2022)

The Preferred Portfolio includes the addition of 120 MW of solar PV capacity in 2022. This capacity is associated with a PPA Idaho Power signed to purchase output from the 120 MW Jackpot Solar facility having a projected commercial on-line date of December 2022. The PPA for Jackpot Solar was approved by the IPUC on December 24, 2019.

Exit from Coal-Fired Generating Capacity

The Preferred Portfolio includes Idaho Power's exit from its share of North Valmy Unit 1 by year-end 2019, Boardman by year-end 2020, a Jim Bridger unit during 2022, North Valmy Unit 2 by no later than year-end 2025 and no earlier than year-end 2022, and a second Jim Bridger unit during 2026. The achievement of these coal-unit exits is expected to require substantial coordination with unit co-owners, regulators, and other stakeholders. The company also recognizes the need to ensure system reliability is not jeopardized by coal-unit exits~~,~~ and considers B2H as a necessary resource in enabling the proposed coal-unit exits.

Valmy Unit 2 Exit Date

As discussed in Chapter 1, the exit timing of Valmy Unit 2 requires further analysis, which Idaho Power plans to conduct in the coming months.

Potential savings based on a long-term analysis should not be the sole consideration. Rather, near-term economic and reliability impacts of an earlier exit must also be evaluated using data points such as forward market hub price forecasts, planned unit outages, Idaho Power's energy risk management processes, and recent market conditions, among other items.

In the months ahead, Idaho Power will conduct further analysis of Valmy Unit 2 exit timing. In particular, the company will assess the feasibility of a 2022 exit, which would require 15 months of advance notice to the plant operator (i.e., a decision before September 30, 2021). The analysis will consider customer reliability, more current operating budgets, and economics to inform a decision that will minimize costs for customers while ensuring Idaho Power can maintain system reliability.

B2H On-line in 2026

The Preferred Portfolio includes the B2H transmission line with an on-line date during 2026. Continued permitting and construction activities are included in the IRP Action Plan.

Demand Response

~~The company acknowledges that~~ Under the ~~amended preferred portfolio, some~~Preferred Portfolio in this *Second Amended 2019 IRP*, demand response ~~was shifted into future years outside~~is added one year earlier than previously identified in the Preferred Portfolio of the ~~action plan window in comparison to the 2019 IRP preferred portfolio~~*Amended 2019 IRP*, filed in ~~June 2019. The company examined the cost associated with accelerating~~January 2020. Demand response ~~within the amended preferred portfolio and found accelerating demand response added nearly $900,000 to the preferred portfolio NPV. In moving forward with the amended preferred portfolio as least-cost, least-risk, the company acknowledges the benefit of demand response and~~ additions are also expanded from 30 MW over six years to 45 MW over nine years. The company will continue to evaluate the cost and risk associated with accelerating and expanding demand response ~~to earlier years~~programs.

Action Plan (~~2019~~2020–2026)

Table 10.3 Action Plan (~~2019~~2020–2026)

Year	Action
~~2019~~2020–2022	Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition.
~~2019~~2020-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
~~2019~~	~~Jackpot Solar PPA regulatory approval*—on-line December 2022~~
~~2019~~	~~Exit Valmy Unit 1 by December 31, 2019.*~~
~~2019~~2020–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
~~2019~~2020–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
~~2019–~~2020	Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.
2020	Exit Boardman December 31, 2020.
2020	Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.
2020	Conduct a VER Integration Study.
2020–2021	Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2.
2021–2022	Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
2022	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.

2022	Jackpot Solar 120 MW on-line December 2022.
~~2023–2026~~	~~Procure or construct resources resulting from RFP (if needed).~~
~~2025~~2022	Exit Valmy Unit 2 by December 31, ~~2025.~~2022.*
2026	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H).

Jackpot Solar PPA and the Valmy Unit 1 exit were complete at the time the *Second Amended 2019 IRP* was filed on October 2, 2020.

* Further analysis will be conducted to evaluate the optimal exit date of Valmy Unit 2, weighing exit economics and system reliability concerns. Further discussion of the Valmy Unit 2 is provided in the Valmy Unit 2 Exit Date section of Chapter 1 of this document.

Conclusion

The *Second Amended 2019 IRP* provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. The B2H transmission line continues in the 2019 IRP analysis to be a top-performing resource alternative providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market. From a regional perspective, the B2H transmission line, and high-voltage transmission in general, is ~~a~~ critical ~~part~~ to ~~the achievement of~~achieving clean energy objectives, including Idaho Power's 2045 clean energy goal.


Idaho Power linemen install upgrades.

The cost competitiveness of PV solar is another notable theme of the 2019 IRP. The Preferred Portfolio for the *Second Amended 2019 IRP* includes a PPA to purchase output from 120 MW of PV solar projected on-line in December 2022. Idaho Power's IRP analysis indicates this contract allows the cost-competitive acquisition of PV solar energy, and further positions the company in its achievement of long-term clean energy goals.

The *Second Amended 2019 IRP* indicates favorable economics associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026, and exit from the remaining two units at the Jim Bridger facility by the end of the 2020s. Idaho Power views this strategy as consistent with its long-term clean energy goals and transition from coal-fired generation, and further sees the B2H transmission line as a resource critical to enabling the exit from coal-fired generation.

Idaho Power recognizes its obligation to reliably deliver affordable electricity to customers cannot be compromised as it strives to achieve clean energy goals and emphasizes the need to continue to evaluate the coal-fired 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 exit, may require the preferred portfolio's flexible capacity resources to be on-line sooner than planned.

Idaho Power strongly values public involvement in the planning process~~. Idaho Power~~ and thanks the IRPAC members and the public for their contributions ~~to~~throughout the entire 2019 IRP process. The IRPAC discussed many technical aspects of the 2019 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~~ and~~. The next plan will be filed in 2021. The energy industry is expected to continue ~~to undergo~~undergoing substantial transformation over the coming years, and new challenges and questions will be encountered in the 2021 IRP. Idaho Power will continue to monitor trends in the energy industry and adjust as necessary in the 2021 IRP.