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October 2, 2020

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket LC 74 – Idaho Power Company's 2019 Integrated Resource Plan ("IRP")

Attached for filing in the above-captioned docket is Idaho Power Company's Amended IRP Application.

Please contact this office with any questions.

Thank you,

Alisha Till

Alisha Till
Paralegal

Attachments

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

In the Matter of IDAHO POWER COMPANY 2019 Integrated Resource Plan	**IDAHO POWER COMPANY'S AMENDED IRP APPLICATION**

I. INTRODUCTION

Idaho Power Company (Idaho Power or Company) respectfully submits this Second Amended 2019 Integrated Resource Plan (*Second Amended 2019 IRP*)[1] for consideration and acknowledgement by the Public Utility Commission of Oregon (Commission), in accordance with Order Nos. 89-507, 07-002, 07-747, 12-013, and 18-176.[2]

Idaho Power greatly appreciates the Commission and other parties' patience as the Company conducted a thorough review and end-to-end re-run of its IRP in this proceeding. Idaho Power believes that this careful, comprehensive review process will ensure that future IRPs proceed more smoothly and continue to yield resource portfolios that balance cost, risk, and the Company's commitment to clean energy.

This *Second Amended 2019 IRP* results in only one change to the Company's near-term Action Plan—the exit year for the Valmy Unit 2 coal-fired power plant. Idaho Power initially

[1] The complete *Second Amended 2019 IRP* consists of five separate documents: (1) the *Second Amended 2019 Integrated Resource Plan*; (2) Appendix A: Sales and Load Forecast; (3) Appendix B: DSM Annual Report; (4) Appendix C: Technical Report; and (5) Appendix D: B2H Supplement. A copy of the complete *Second Amended 2019 IRP* is provided as Attachment 1 and can also be found on the Company's website at www.idahopower.com. As a courtesy to our readers, Idaho Power has provided a redline version of the documents where changes were made -- the Plan, Appendix C, and Appendix D -- in Attachment 2. The Company also submits its 2019 IRP Review Report documenting its review of the entire IRP development process as Attachment 3. Interested persons may request a printed copy of these documents by contacting irp@idahopower.com.

[2] As set forth in the Company's initial Application in this docket, Idaho Power has, consistent with the Commission's direction in Order No. 18-176, (1) included additional information on the progress of the Energy Gateway transmission project, (2) reported on future expanded energy efficiency opportunities and improvements to avoided cost methodology, and (3) described the risks to the Company and its customers associated with climate change. *See* Application at 10-15 (June 28, 2019).

identified a Unit 2 exit by year-end 2025, but analysis as part of the *Second Amended 2019 IRP* revealed the potential for additional savings from an exit as early as year-end 2022. In the coming months, the Company will conduct further analysis to identify optimal unit exit timing that carefully weighs customer economics and reliability concerns and ensures adequate capacity.

The Company's final IRP continues to demonstrate a clear trajectory toward Idaho Power's clean energy future, as reflected in the key resource decisions in the Company's Preferred Portfolio: (1) 400 megawatts (MW) of new solar generation; (2) development of the Boardman-to-Hemingway (B2H) transmission line; and (3) complete exit from coal resources by 2030. The development of B2H, in particular, provides a crucial carbon-free, supply-side resource that supports renewables and enables the Company's transition away from coal.

Idaho Power's *Second Amended 2019 IRP* provides a robust analysis of the long-term planning and resource decisions needed to affordably and reliably serve customers. Idaho Power therefore respectfully requests that the Commission acknowledge this final 2019 IRP and the Company's Action Plan items.

Idaho Power intends to work with OPUC Staff and intervening parties to develop a schedule in this case that allows for a Commission decision by February 26, 2021. This proposed review period should be adequate given the scrutiny already given the Amended 2019 IRP, the robustness of the IRP review process by Idaho Power, and the fact that the changes to the conclusions and actions contained in this second amendment are relatively modest. A decision by February of 2021 is important to the Company for two reasons. The contested case process for a site certificate for B2H is currently ongoing before the Energy Facility Siting Council. A timely decision in this IRP proceeding will provide invaluable context for the EFSC proceeding by further clarifying the Company's need to develop this important project. Moreover, an expeditious conclusion of this IRP will position the Company to begin engaging with stakeholders on the 2021 IRP, with a goal of filing that IRP in the latter part of 2021.

II. DISCUSSION

Idaho Power filed its original IRP on June 28, 2019, and its Amended 2019 IRP on January 31, 2020.[3] 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. To allow time for the Company to complete this review, on July 1, 2020, Idaho Power filed a Motion to Suspend the Procedural Schedule. This Motion was granted on July 2, 2020, with the understanding that the Company would conclude its review and propose a revised procedural schedule by July 31, 2020.[4]

A. Idaho Power Comprehensively Reviewed the IRP Cycle.

During July of 2020, Idaho Power convened a team of subject matter experts (IRP Review Team) to perform a comprehensive four-step review to deconstruct and examine all aspects of the IRP analysis, from model inputs to model outputs. The IRP Review Team included members of the Planning, Engineering & Construction, Power Supply, and Finance departments, with additional support and consultation from members of the Internal Audit and Regulatory Affairs departments to ensure a consistent and methodical review. The IRP Review Team conducted its analysis in four steps:

- ***First,*** the IRP Review Team examined input data related to the IRP process. This process involved 11 sub-teams to examine categories of AURORA model data and cross-verifying this data against source materials. This step also included reviewing regulatory decisions and orders that direct specific AURORA input treatment.

[3] On May 29, 2020, Idaho Power provided a correction to the IRP related to the costs associated with the Jim Bridger Power Plant (Bridger). This correction required the replacement of seven pages in the Company's Amended IRP but did not impact the Company's recommendation of the Preferred Portfolio, which remained the least-cost, least-risk solution to serve customers.
[4] Docket LC 74, Ruling (July 2, 2020).

- ***Second,*** the IRP Review Team evaluated how data were modified or converted as part of incorporating it into the AURORA model, to ensure that any transformations or conversions were conducted properly.
- ***Third***, the IRP Review Team examined the modeling logic that AURORA used to analyze the data, to verify and validate that the model itself was functioning in a logical manner and consistent with Idaho Power's knowledge of its own system and resources.
- ***Fourth,*** the IRP Review Team analyzed results to ensure that the outputs were consistent, logical, and accurate.

On July 31, 2020, Idaho Power updated the Commission and parties that the Company had concluded the detailed internal review and intended to perform a new end-to-end portfolio analysis. The Company committed to conduct this final IRP analysis and present a finalized Preferred Portfolio and near-term action plan by October 2, 2020.

B. Idaho Power's Updated IRP Portfolio Modeling Strengthened the Company's Analysis.

Idaho Power's *Second Amended 2019 IRP* applied an updated portfolio analysis process compared to that used in the previous Amended 2019 IRP. The process of conducting *the Second Amended 2019 IRP* was bolstered by the findings of the IRP Review, which resulted in adjustments to model inputs and model operations.[5] Further, the updated portfolio selection and adjustment process in the *Second Amended 2019 IRP* included a number of methodological and modeling adjustments, including an expanded array of resource options (such as pumped hydro storage, geothermal, and accelerated North Valmy Unit 2 exit), a wider range of Western Electricity Coordinating Council (WECC)-optimized resource mixes that were used as a starting

[5] 2019 IRP Review Report, Attachment 3 to the *Second Amended 2019 IRP*.

point for manual optimization, and a strengthened manual adjustment process. The Company's portfolio modeling proceeded in the following steps:

- Idaho Power formed the IRP Review Team to provide clarity around the entire IRP development process. The team's objectives were to verify the modeling of key inputs, validate model outputs, ensure consistency and accuracy in each step of the IRP modeling process, and identify appropriate and efficient resolutions for any identified adjustments. The resulting 2019 IRP Review Report, filed in conjunction with the *Second Amended 2019 IRP*, provides lessons learned that were not only applied to Idaho Power's final 2019 IRP but can be used in the development of future IRPs to ensure the process is more efficient, transparent, and accurate.
- Following the input and modeling adjustments identified in the review process, Idaho Power used AURORA's Long-Term Capacity Expansion (LTCE) model to produce 24 different portfolios, based on a combination of three natural gas price forecasts and four carbon cost forecasts. Each of these forecast combinations were examined both with and without B2H. These portfolios were optimized for the WECC region, not necessarily for Idaho Power's service area.
- From the 24 WECC-optimized portfolios, Idaho Power identified six starting points for manual adjustment with the objective of further reducing Idaho Power-specific portfolio costs while maintaining reliability. These six portfolios reflect a broader selection of resource types, amounts, and timing compared to the four portfolios selected for manual adjustment in the Amended 2019 IRP.
- Each of the six portfolios were tested under four future natural gas and carbon price conditions (Planning Gas-Planning Carbon, High Gas-Planning Carbon, Planning Gas-High Carbon, and High Gas-High Carbon) for both B2H and non-B2H alternatives.

- The manual adjustment process focused on identifying optimal exit scenarios for the Jim Bridger coal units. Additionally, the Company performed sensitivity analysis of a year-end 2022 exit from Valmy Unit 2, rather than a year-end 2025 exit.
- Upon completion of the manual adjustments, the 24 final portfolios were evaluated in each of the four natural gas and carbon price conditions using the AURORA model to determine their net present value.
- Idaho Power applied a stochastic risk analysis to understand each portfolio's sensitivity to changes in natural gas prices, customer load, and hydroelectric variability. This step remained similar to that performed in the previous Amended IRP.

In total, the Company's updated portfolio modeling analysis evaluated 48 portfolios, 24 of which were developed by the LTCE model for optimization in the WECC region, and 24 of which were developed through the manual refinement process.

C. Idaho Power's Preferred Portfolio and Action Plan Enables Idaho Power's Clean Energy Future.

The Company's new end-to-end IRP produced a Preferred Portfolio and Action Plan that continues to support the Company's key action items as set forth in the previous Amended IRP. Crucially, the *Second Amended 2019 IRP* continues to show a clear path toward a clean energy future through the procurement of new solar resources, a transition away from coal, and the development of B2H as a least-cost and carbon-free supply-side resource.

Specifically, the *Second Amended 2019 IRP* analysis identified the Company's Preferred Portfolio as the Planning Gas/Planning Carbon scenario with B2H; exit dates for the Jim Bridger units in 2022, 2026, 2028, and 2030; and potential exit from Valmy Unit 2 in 2022.[6] The updated Action Plan continues to support the same three core resource actions in the Preferred Portfolio of the Amended IRP, including (1) adding 120 MW of solar capacity by 2022; (2) exiting from four

[6] The specific exit date for Valmy Unit 2 remains subject to further analysis of economic and reliability concerns.

coal-fired generating units by year-end 2022, and from a total of five of the Company's seven coal-fired units by year-end 2026; and (3) the completion and operation of B2H in 2026.

Below is a summary of the Company's updated Action Plan.[7] The updated Preferred Portfolio results in only one potential change to Idaho Power's near-term 2020-2026 Action Plan—the exit timing of Valmy Unit 2. The Valmy Unit 2 exit is currently reflected as year-end 2022, but the exit window is subject to ongoing analysis to identify an optimal date between year-end 2022 and year-end 2025.

Year	Action
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.
2020-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
2020–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
2020–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
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.
2022	Exit Valmy Unit 2 by December 31, 2022.[8]
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).

Over the modeling time horizon, the Preferred Portfolio in the *Second Amended 2019 IRP* includes a number of additional changes from the previous analysis, including reductions in new

[7] The Jackpot Solar Power Purchase Agreement and the Company's exit from Valmy Unit 1 are not listed in the Action Plan, as these items were completed in 2019.
[8] As noted earlier, the specific exit date for Valmy Unit 2 remains subject to further analysis of economic and reliability concerns.

wind and solar in the latter years of the analysis (reflecting the diminishing contribution of these resources to Idaho Power's peak load), as well as a 15 MW increase in demand response, bringing the total amount in the Preferred Portfolio to 45 MW. Idaho Power believes that these updates to the Company's IRP provide a clear and reliable path forward in pursuit of a clean energy future, while ensuring the least-cost, least-risk set of resources to meet customer needs and ensure reliability.

III. CONCLUSION

Idaho Power recognizes that the Company's 2019 IRP has proceeded on an extended timeframe, including both this comprehensive update as well as previous updates and amendments. The Company appreciates the opportunity to ensure that its planning practices are complete and correct and believes that the process will help ensure that future IRP proceedings are more efficient, transparent, and replicable. And most importantly, the Company believes that the improved processes will support the Commission and stakeholders' confidence in this *Second Amended 2019 IRP*. For these reasons, Idaho Power respectfully requests that the Commission acknowledge Idaho Power's *Second Amended 2019 IRP* and Action Plan.

DATED: October 2, 2020.

McDOWELL RACKNER GIBSON PC

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

IDAHO POWER COMPANY

Attachment 1

2019 Second Amended Integrated Resource Plan

October 2, 2020

IDAHO POWER
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED

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
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'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 and the associated appendices are intended to replace both the initial IRP, filed on June 28, 2019, as well as the Amended 2019 IRP, filed on January 31, 2020. For the sake of clarity, the company believes 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 detailing elements that changed and those that did not. .

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 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 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.

Overall, the results of the *Second Amended 2019 IRP* continue to support a number of key components that position Idaho Power to reliably and cost-effectively serve 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 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 the company worked through the modeling challenges presented by its first time using a computer-based optimizer to construct resource portfolios. From Idaho Power's concentrated efforts on the IRP, Idaho Power 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.

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. 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 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 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 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.

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[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 can be expected under an alternative future scenario using a high natural gas price forecast and/or high cost of carbon to produce a portfolio having substantial expansion of non-carbon emitting 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, 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.

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 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 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.

While an IRP addresses Idaho Power's long-term resource needs, near-term energy and capacity needs are planned in accordance with the company's *Energy Risk Management Policy* and *Energy Risk Management Standards*. The risk management standards were collaboratively developed in 2002 among Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The *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'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 carbon emissions. The Preferred Portfolio was selected in part to further the company's pathway to reduced emissions.

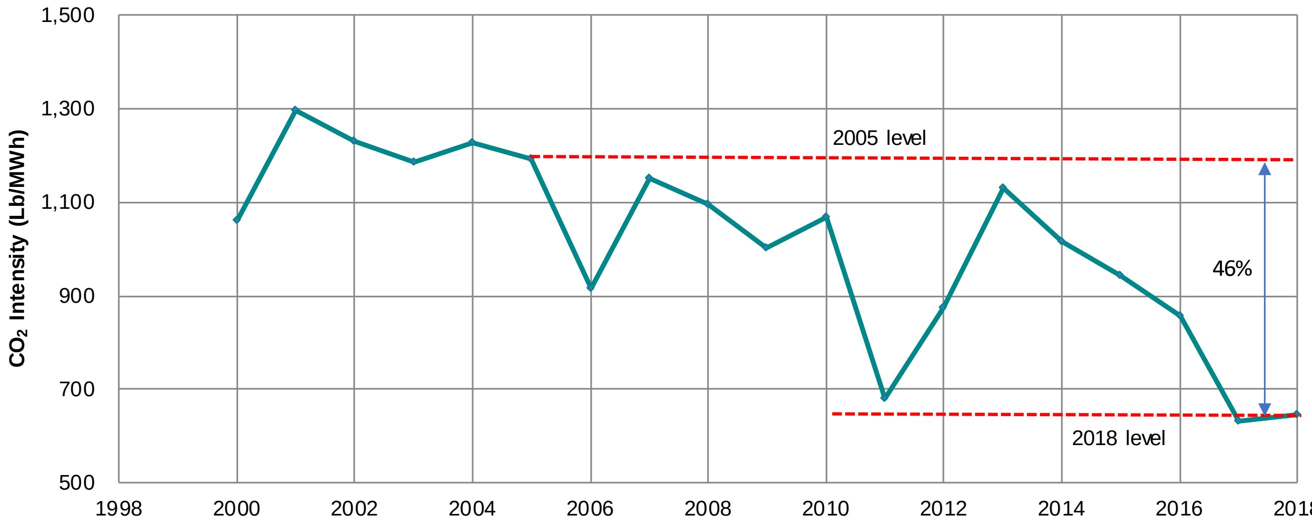

Figure 1.1 Estimated Idaho Power CO_2 emissions intensity

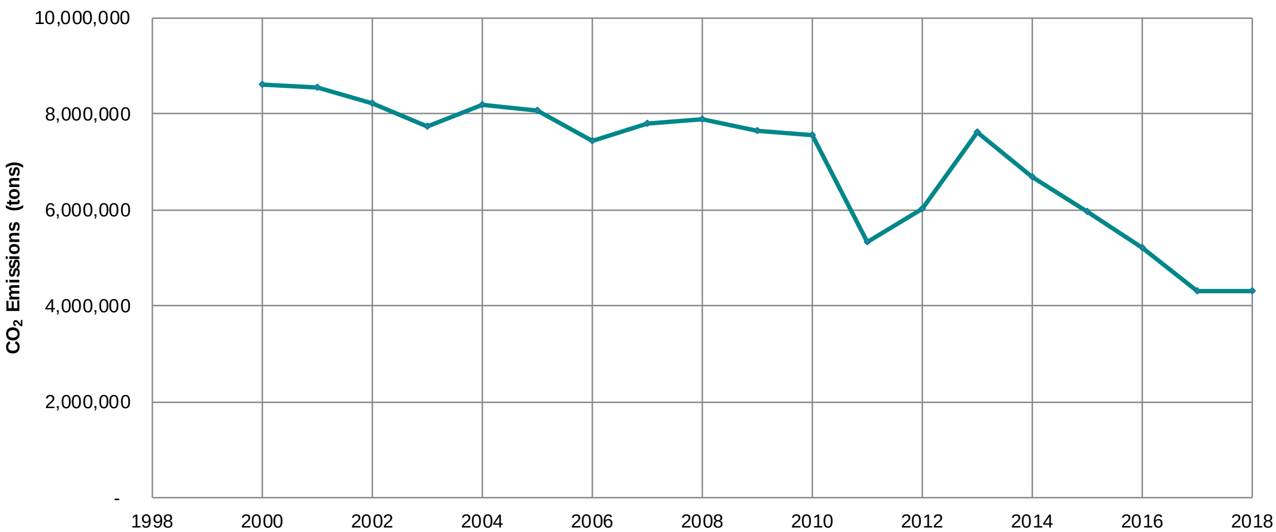

Figure 1.2 Estimated Idaho Power CO_2 emissions

CO_2 Emissions Reduction

Idaho Power is committed to reducing the amount of CO_2 emitted from energy-generating sources. 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 carbon cost forecasts are provided in Chapter 8, while the projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 9.

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

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 the plan contained in the Preferred Portfolio to continue reducing carbon emissions 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 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 technological advances and reductions in cost, as well as a continued focus on energy efficiency and demand-response programs. As it has over the past decade, the IRPAC will continue to play a fundamental role in updating the IRP every two years, including analyzing new and evolving technologies to help the company on its path toward a cleaner tomorrow while providing low-cost, reliable energy to our customers.

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 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 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 200 and 1,170 MW)
- Natural Gas Reciprocating Engines (between 0 and 333 MW)
- Natural Gas Combined-Cycle Combustion Turbine (CCCT) (between 0 and 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 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 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. Analyzing a range of possible futures also allows Idaho Power to identify the cost sensitivity of various resource mixes to alternative future scenarios that helps inform the company's 20-year 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 outcome of the additional modeling 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 PGPC-B2H1) proved to be optimal in the *Second Amended 2019 IRP*. This Preferred Portfolio was derived from a combination of the AURORA LTCE-produced Portfolio 13 and Portfolio 14, with additional manual adjustments to ensure the 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 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					
2030		40	30	5	-177 (Bridger)
2031	300			5	
2032				5	
2033				5	
2034		40	20	5	
2035		80	20	5	
2036		120	10	5	
2037	55.5			5	
2038	55.5			5	
Nameplate Total	**411**	**400**	**80**	**45**	**-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.

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 (2020–2026)

The action plan for the *Second Amended 2019 IRP* reflects near-term actionable items of the Preferred Portfolio. The action plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to our customers into the future. The current regional electric market, regulatory environment, pace of technological change and Idaho Power's goal of 100 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 (2020–2026)

Year	Action
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.
2020-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
2020–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
2020–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
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.
2022	Exit Valmy Unit 2 by December 31, 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 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

Hells Canyon Dam

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.

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,[3] 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.

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

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1 MWh of electricity produced. RECs produced by a certified renewable resource can either be sold together with the energy (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level renewable portfolio standard (RPS). An RPS is a policy requiring a minimum amount (usually a percentage) of the electricity each utility delivers to customers to come from renewable energy resources. 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. In 2019, Idaho Power 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*.

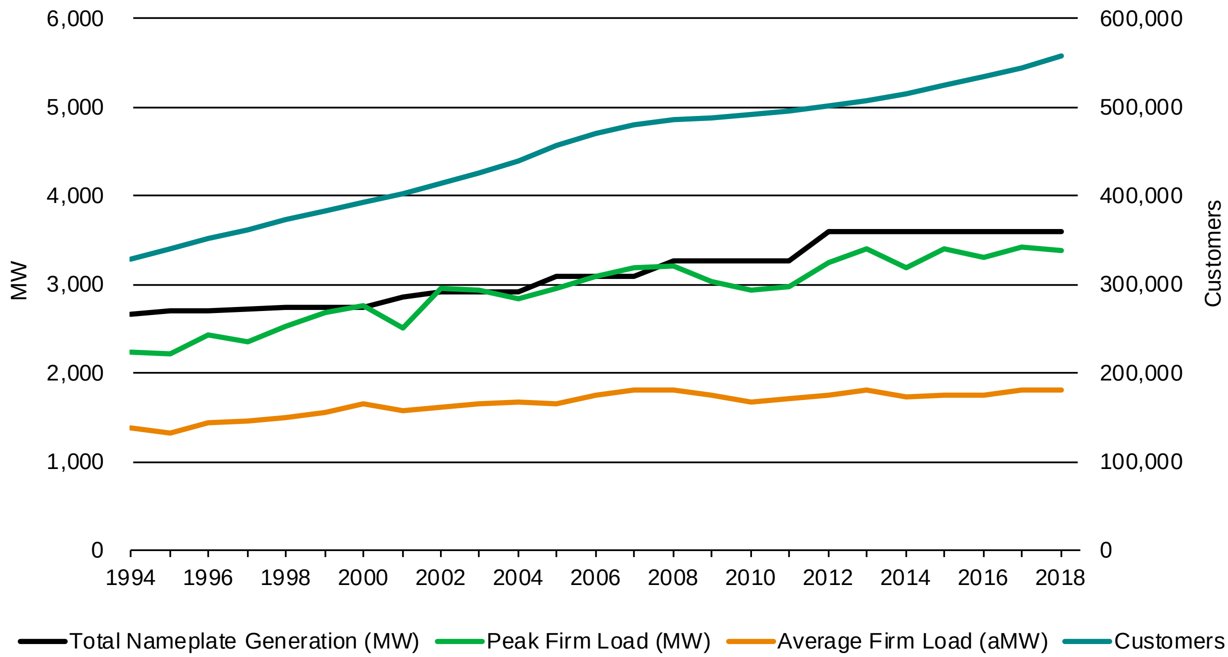

Figure 3.1 Historical capacity, load, and customer data

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.

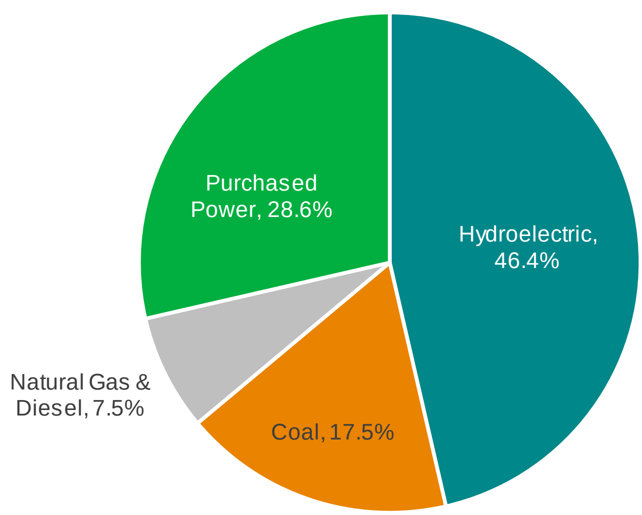

Figure 3.2 2018 energy sources

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.[4] 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

[4] 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,[5] 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

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.

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.

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[5] 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 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

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

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.

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

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

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) 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.

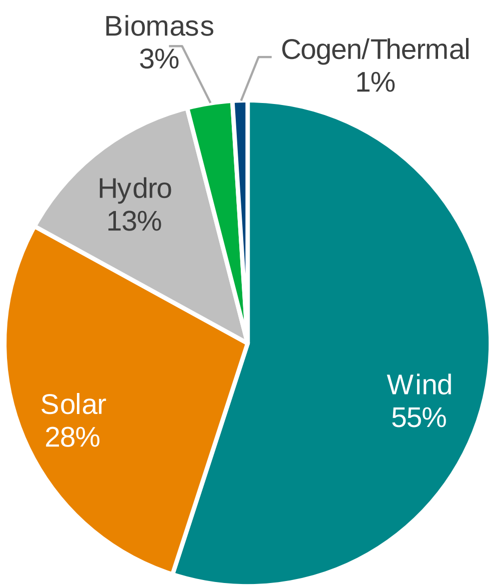


Figure 3.3 PURPA contracts by resource type

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.[6] 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

[6] 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.

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. 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, refer to the Storage Resources section of this chapter.

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[7] 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

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

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.

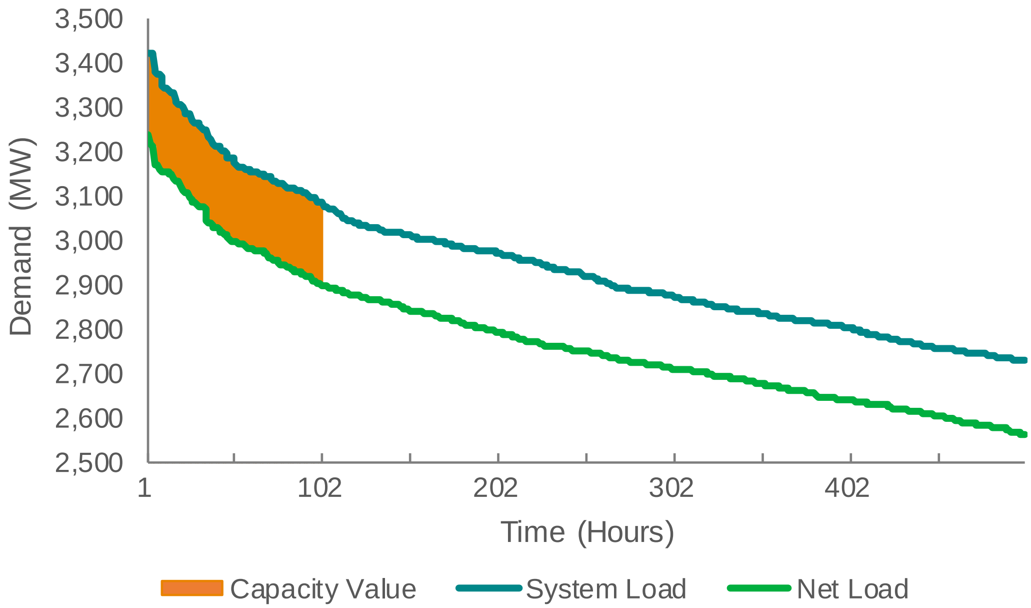


Figure 4.1 Capacity value of solar PV

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.

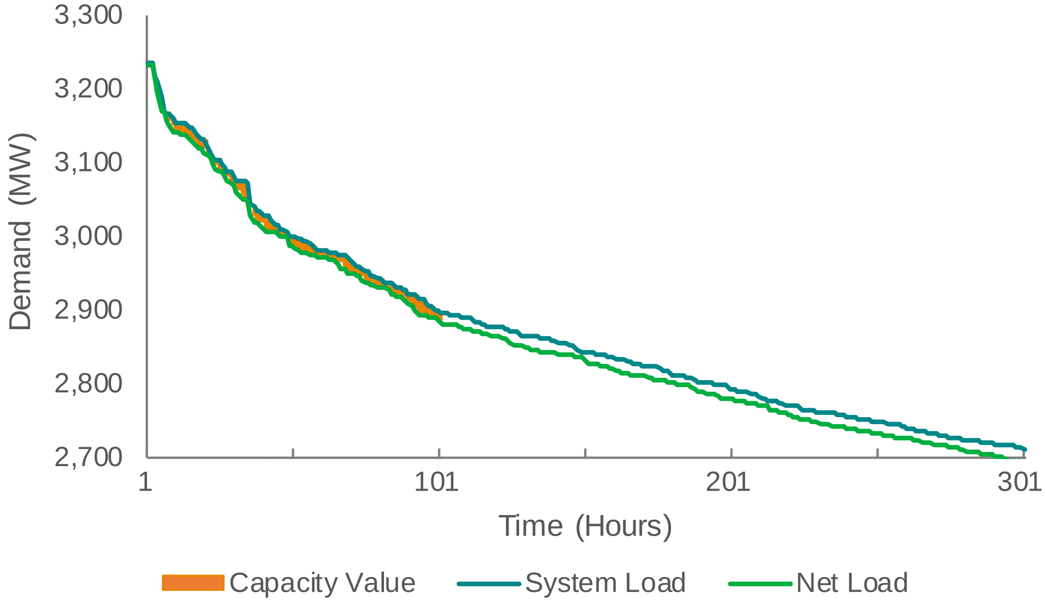


Figure 4.2 Marginal capacity value

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.

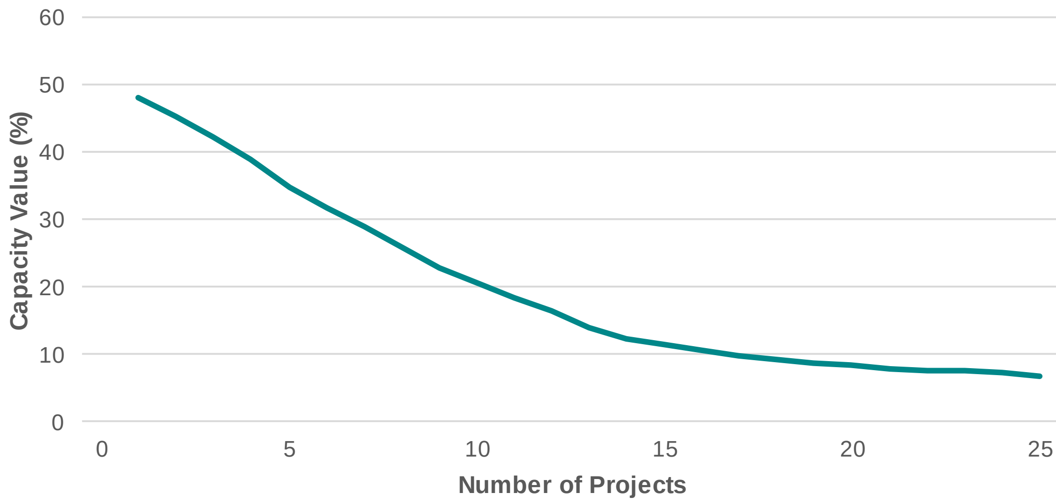


Figure 4.3 Capacity value of incremental solar PV projects (40 MW each)

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 for binary-cycle geothermal generation, see the Supply-Side Resource section of *Appendix C–Technical Appendix* of the *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.

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.

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.

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.

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.

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 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.

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 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*.

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.

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, energy efficiency potential resources have first been forecasted, screened for cost-effectiveness, and then all available 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 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 Energy Efficiency Modeling Methods

Idaho Power tested two alternate 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 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 5.1 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.

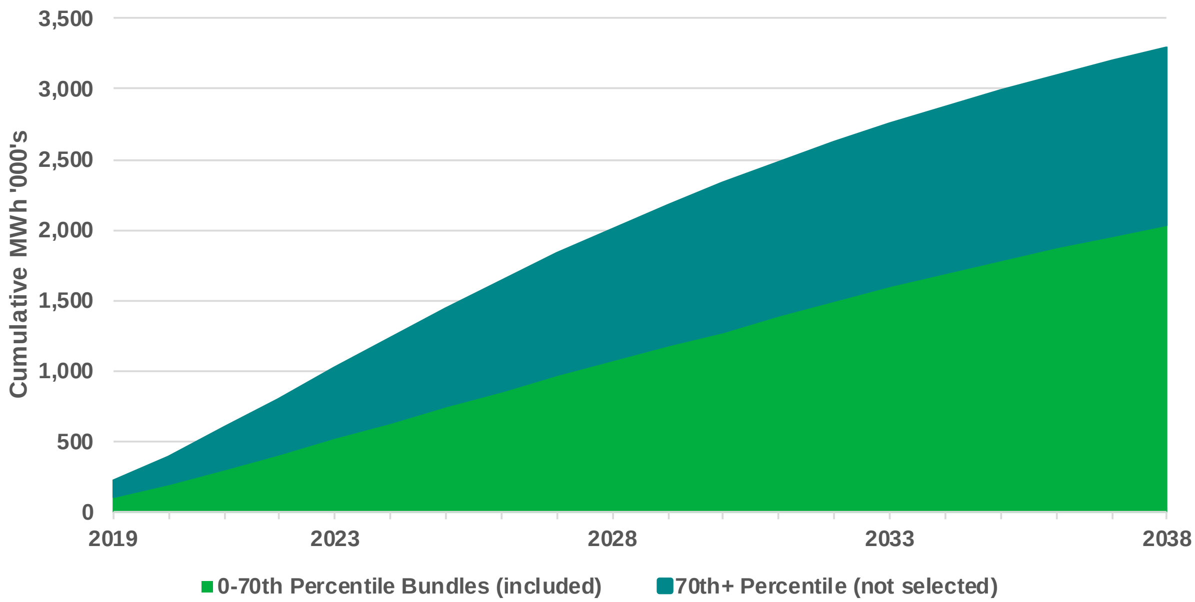


Figure 5.1 **Energy-efficient bundles selected by the IRP model and bundles that were not economically competitive and were not selected for the 2019 IRP portfolios**

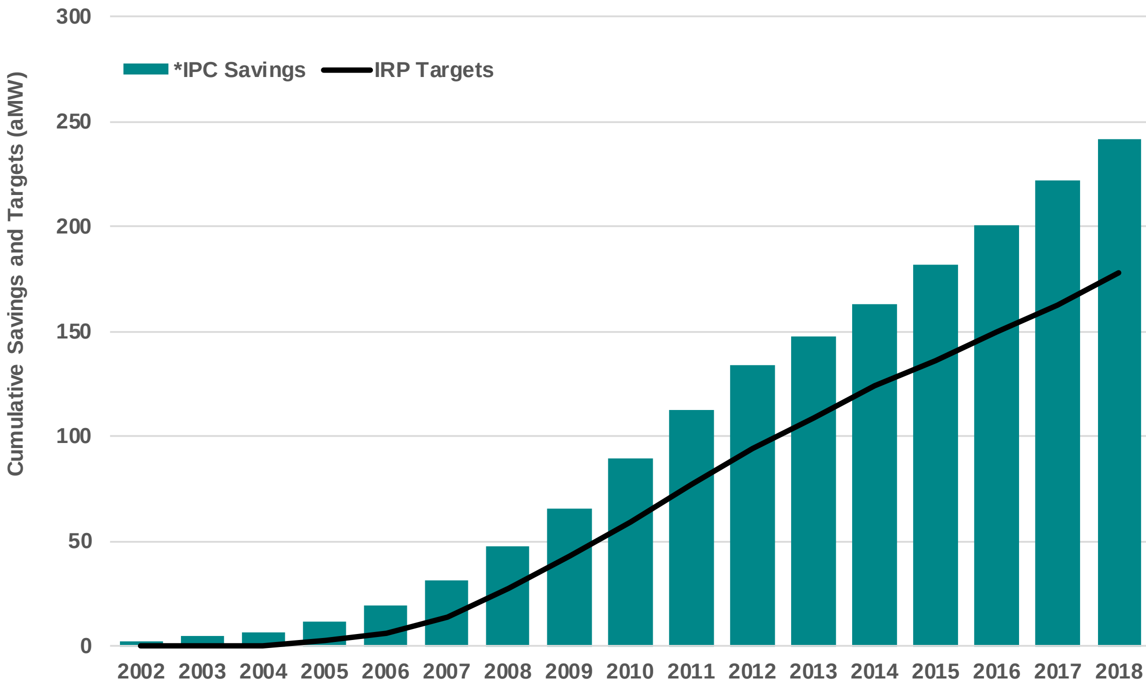
Future Energy Efficiency Potential

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 5.2 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.



* 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 5.3 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.

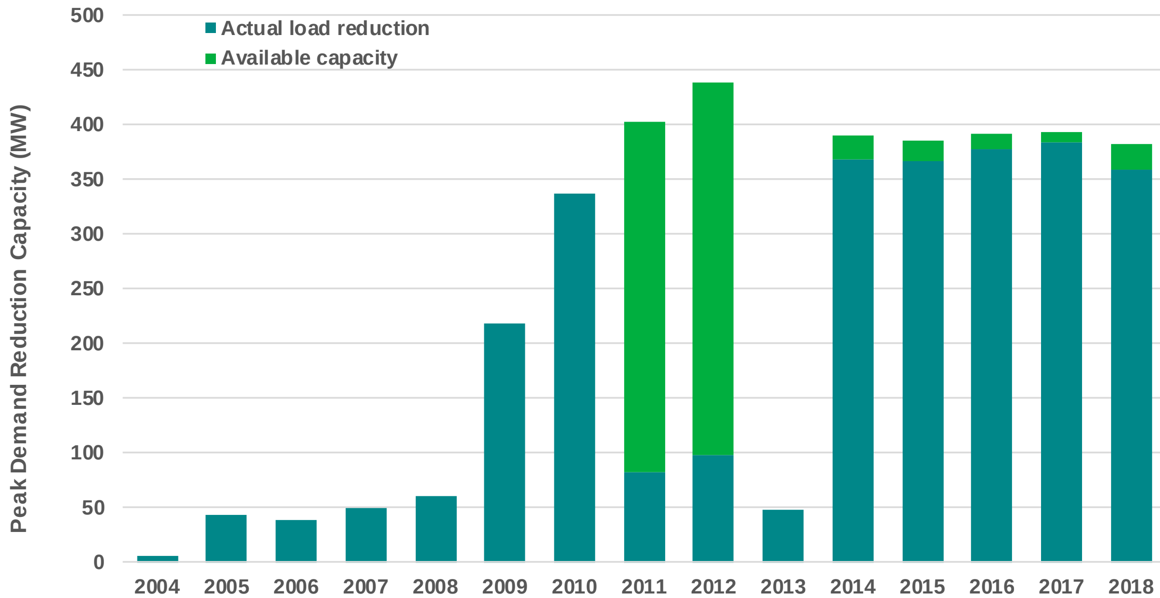


Figure 5.3 Historic annual demand response program performance

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 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 MW the company considers a committed resource, was selected in various amounts by the AURORA LTCE model in 22 of the 24 potential portfolios and was nearly maximized with a total of 45 MW in the Preferred Portfolio.

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. 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 NorthernGrid, a regional transmission planning association of 13 member utilities. The NorthernGrid was formed in early 2020. Previously, dating back to 2007, Idaho Power was a member of the Northern Tier Transmission Group. NorthernGrid membership includes Avista, BPA, Chelan County PUD, Grant County PUD, Idaho Power, Montana–Alberta Tie Line (MATL), NorthWestern Energy, PacifiCorp (Rocky Mountain Power and Pacific Power), Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. Biennially, NorthernGrid will develop a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission 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.

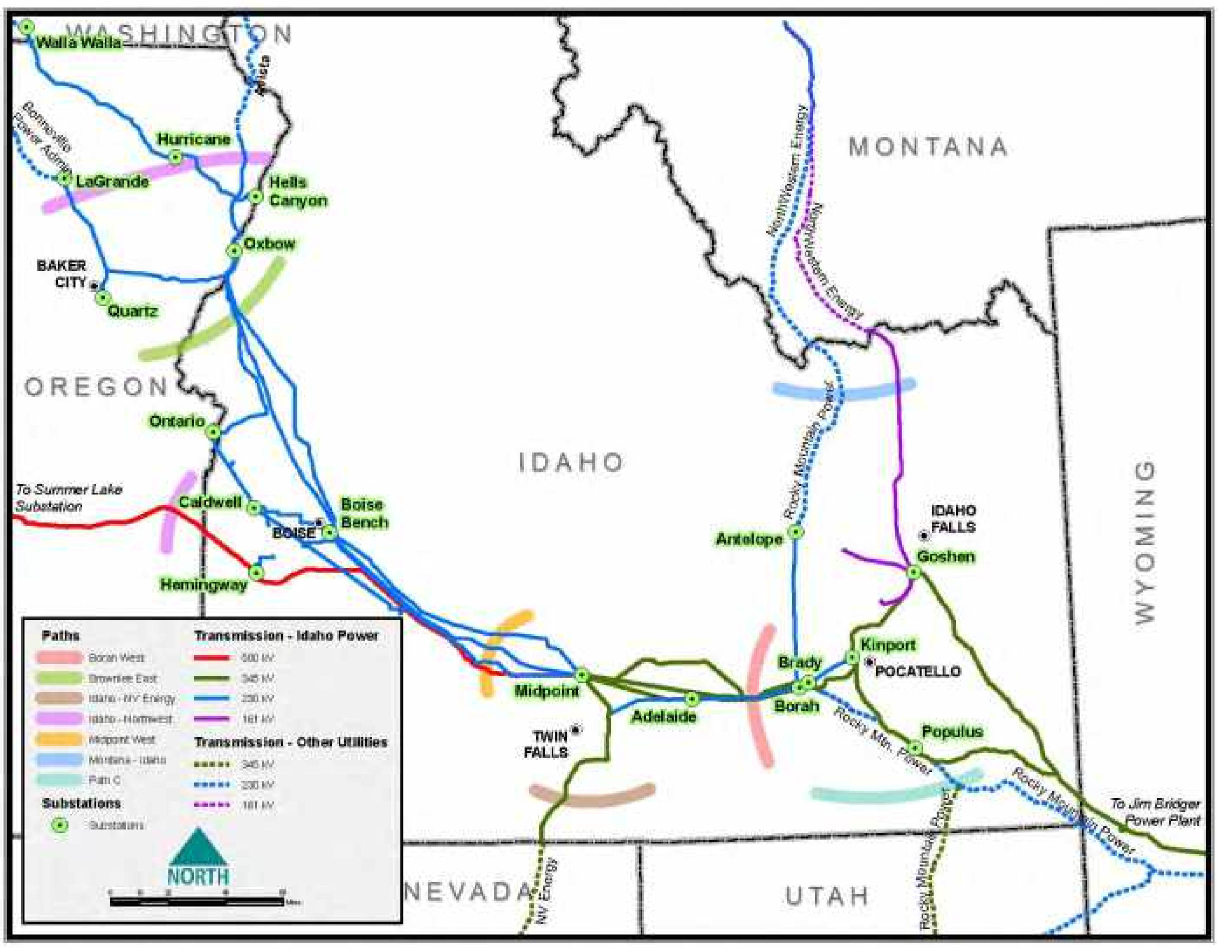


Figure 6.1 Idaho Power transmission system map

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 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. By the end of 2020, the import, or northbound, capacity on the transmission path is 360 MW, of which Valmy 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	Varies by Month
Idaho–Nevada	South to north	360	Varies by Month
Idaho–Montana	North to south	383	Varies by Month
Brownlee East	West to east	1,915	Internal Path
Midpoint West	East to west	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[8], 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.

[8] 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 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 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 Northern Tier Transmission Group (NTTG) biennial regional transmission plan for the past 10 years. NTTG regional transmission plans produce 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,[9] 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

[9] 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 June 30, 2020, BPA and PacifiCorp have collectively invested over $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.

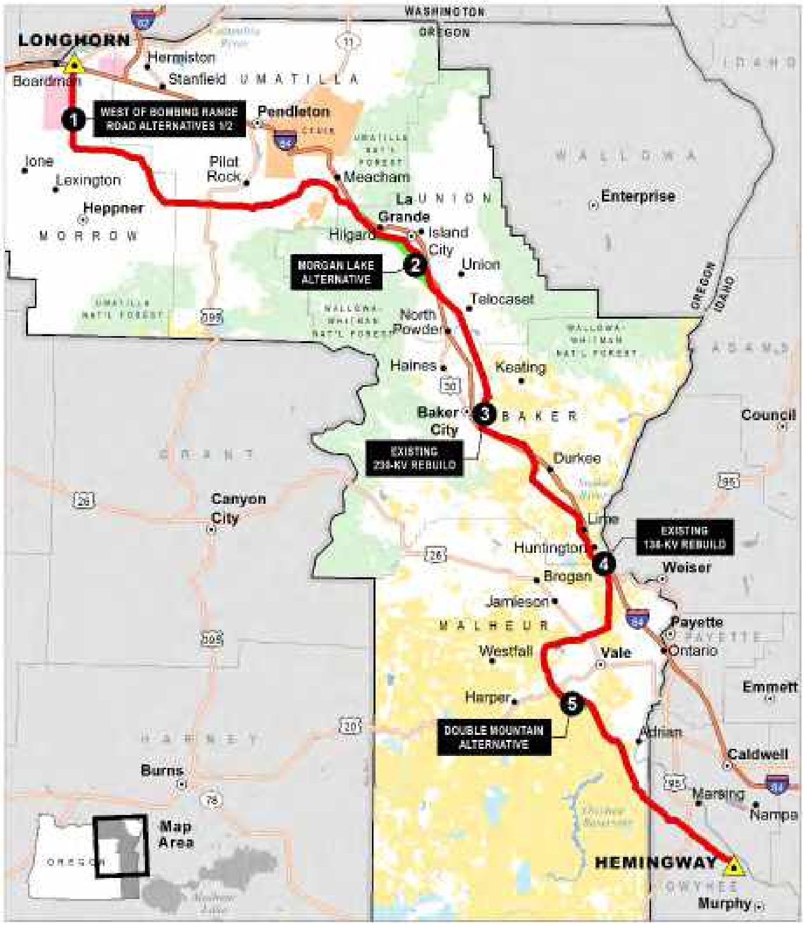


Figure 6.2 B2H route submitted in *2017 EFSC Application for Site Certificate*

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), 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 reviewed the DPO findings, considered public testimony in its review and issued a Proposed Order on July 2, 2020. A contested case on the Proposed Order has been initiated and is being presided over by an EFSC-appointed Administrative Law Judge. Idaho Power currently expects the EFSC to issue a final order and site certificate in the second half of 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 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 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

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

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

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
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 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.

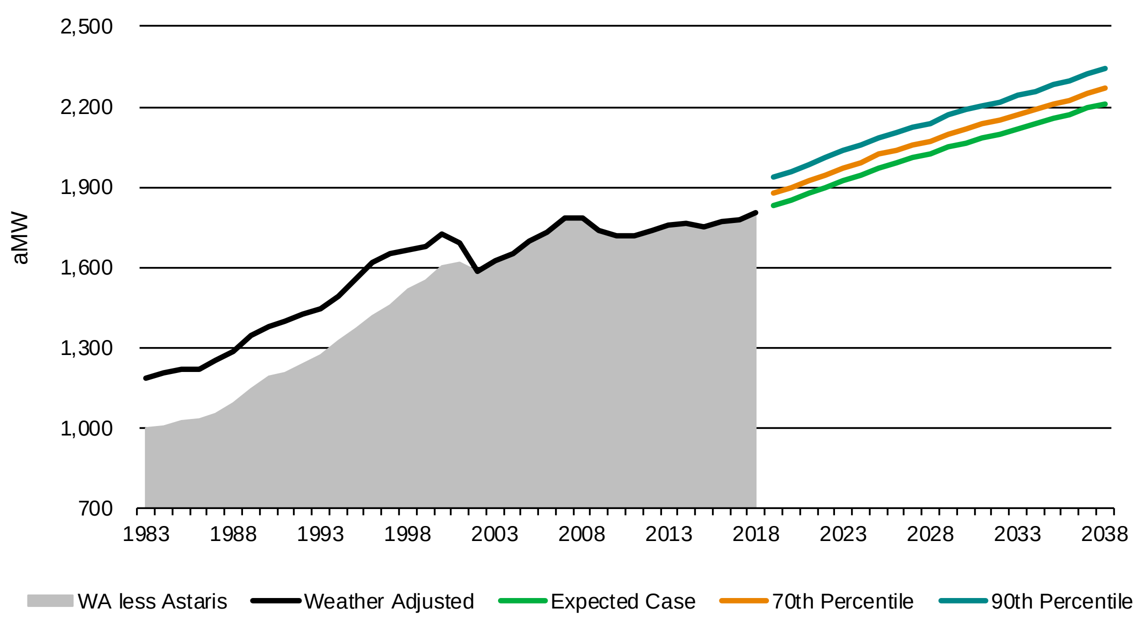


Figure 7.1 Average monthly load-growth forecast

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.

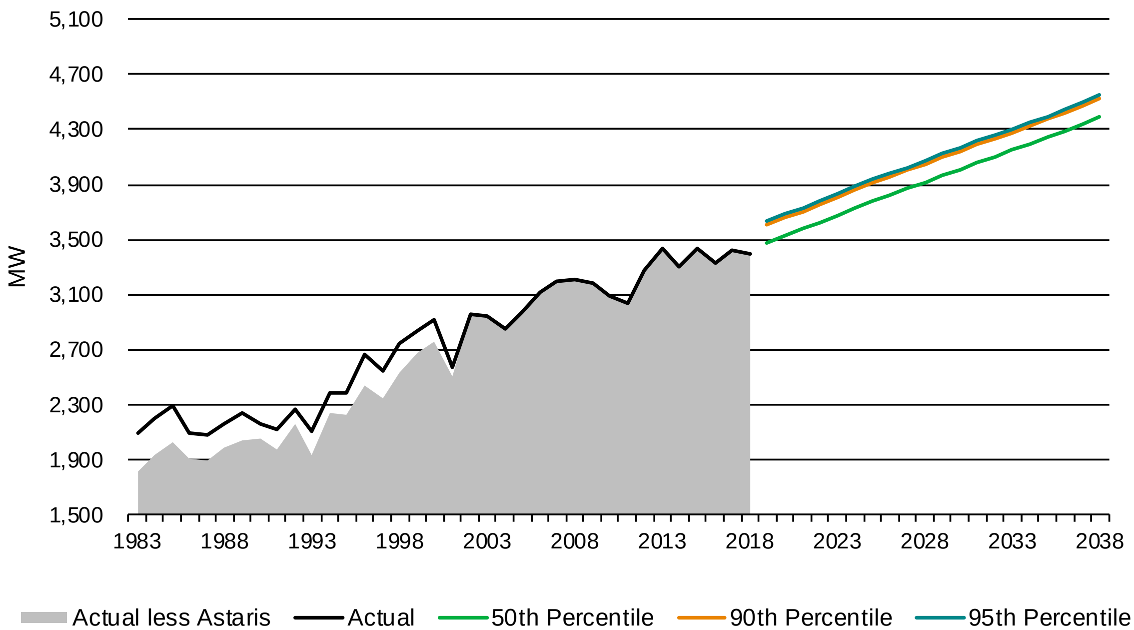


Figure 7.2 Peak-hour load-growth forecast (MW)

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 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 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 50th, 70th, and 90th 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.

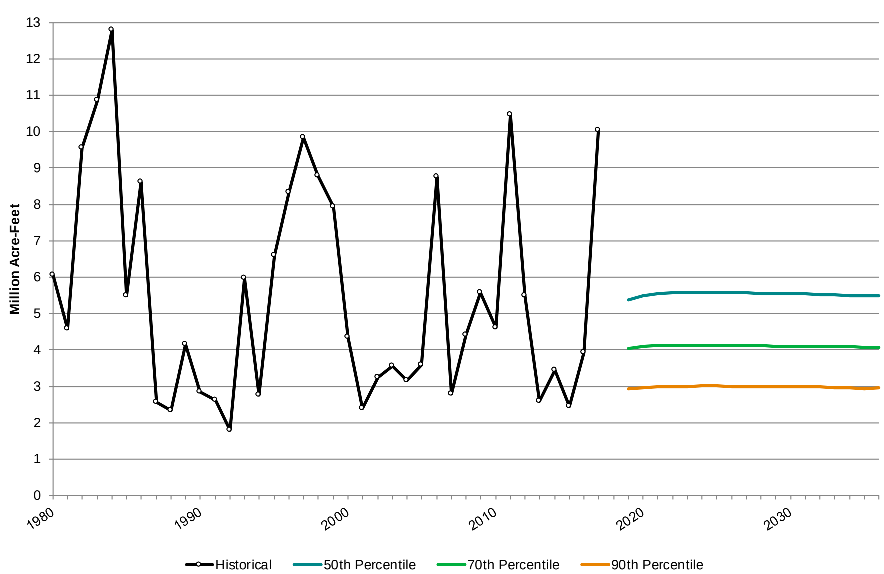


Figure 7.3 **Brownlee inflow volume historical and modeled percentiles**

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[10] and the River Management Joint Operating Committee (RMJOC)[11], 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:

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 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

[10] nca2018.globalchange.gov/downloads/

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

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.

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 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 2026 through 2034
- Unit 3—exit from participation 2028 through 2034
- Unit 4—exit from participation 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, 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 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.

Utility	Gas Price Forecast Methodology
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 helped inform the third-party 2018 natural gas price forecast 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

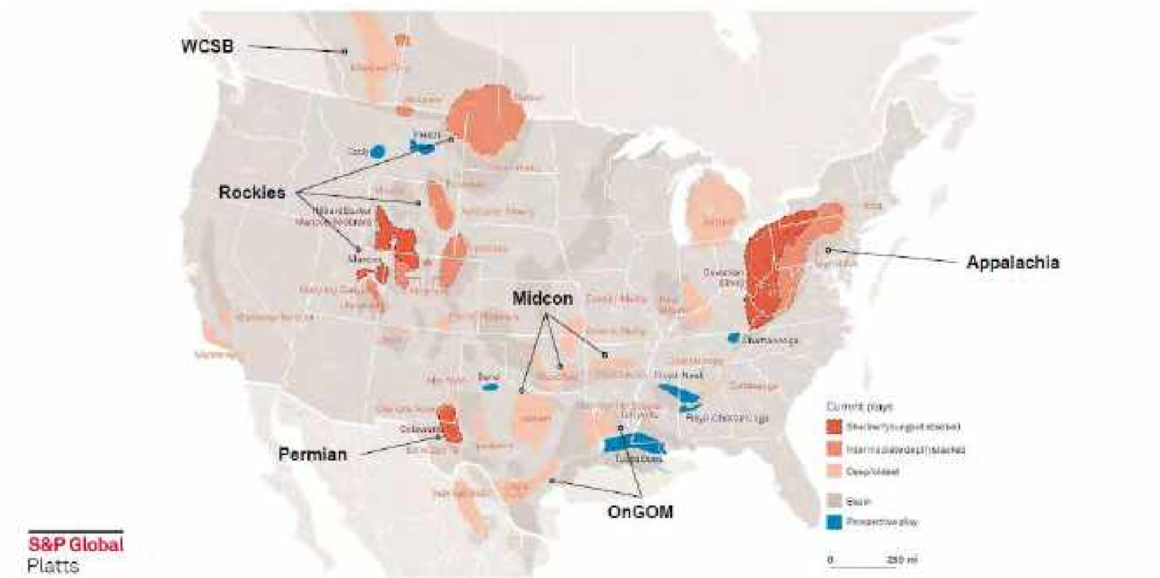


Figure 7.4 North American major gas basins

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.

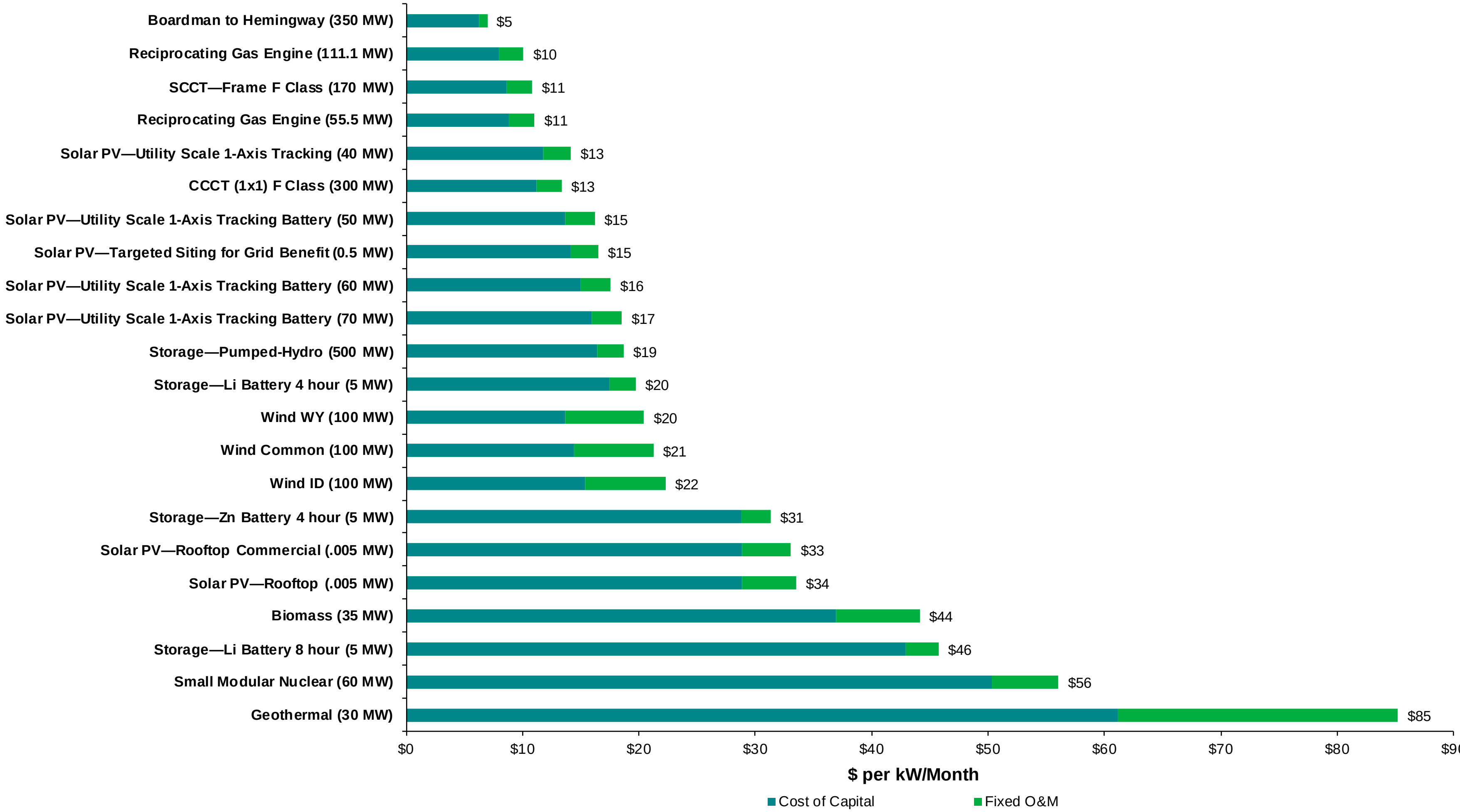


Figure 7.5 Levelized capacity (fixed) costs in 2019 dollars[12]

[12] 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.

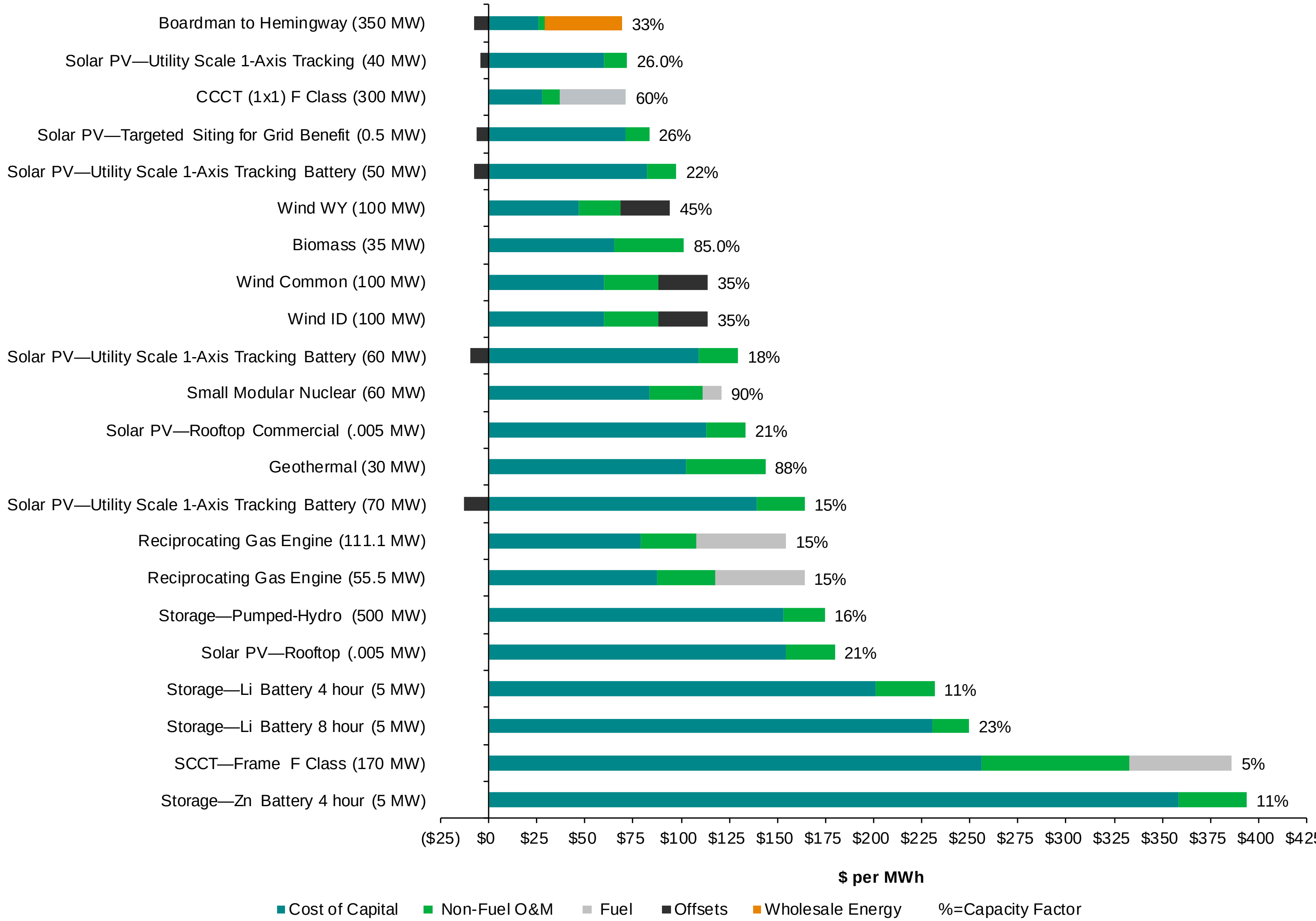


Figure 7.6 **Levelized cost of energy (at stated capacity factors) in 2023 dollars**

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.[13] 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.

[13] 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[14]	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		✓		✓	✓	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 10 MW
Solar PV—AC Coupled with Lithium Battery	✓	✓			✓	Scalable
Storage—Pumped Hydro		✓		✓	✓	500 MW increments
Storage—Lithium Battery		✓		✓		Scalable
Wind (Wyoming/Idaho)	✓				✓	Scalable

[14] 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.[15] Second, it is similar to the methodologies employed by Idaho Power's regional peer utilities for capacity planning.[16]

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.

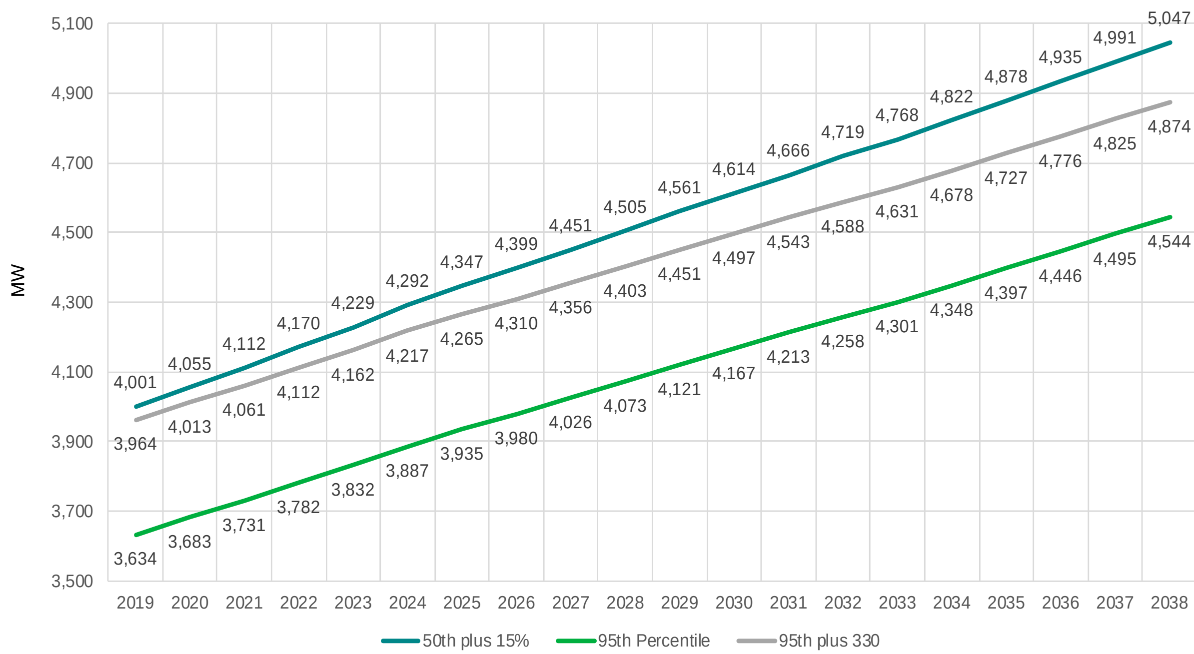


Figure 8.1 2017 versus 2019 IRP planning margin comparison (MW)

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.

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

[16] 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 48 total portfolios, 24 of which were developed by the LTCE model, and 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.[17] 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

[17] 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.[18]

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[19] 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.[20] 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."[21] 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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[18] EIA Annual Energy Outlook 2018, February 2018: eia.gov/outlooks/aeo/pdf/AEO2018.pdf

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

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

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

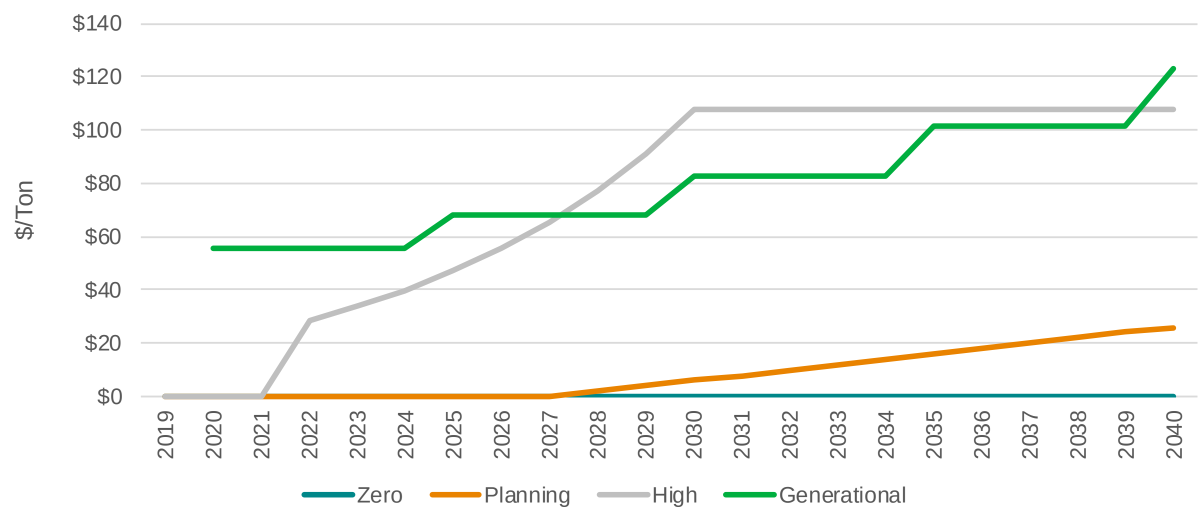

Figure 8.2 Carbon Price Forecast

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*.

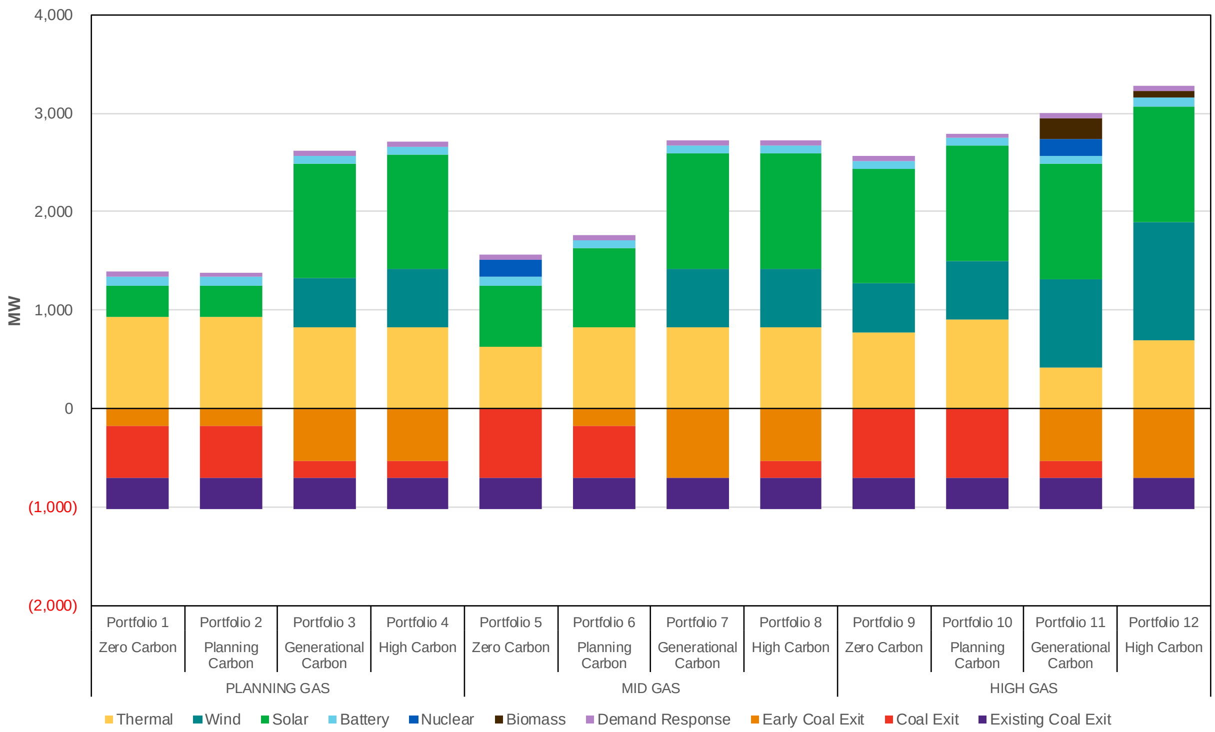

Figure 8.3 WECC-optimized portfolios 1 through 12 (non-B2H portfolios), capacity additions/reductions (MW)

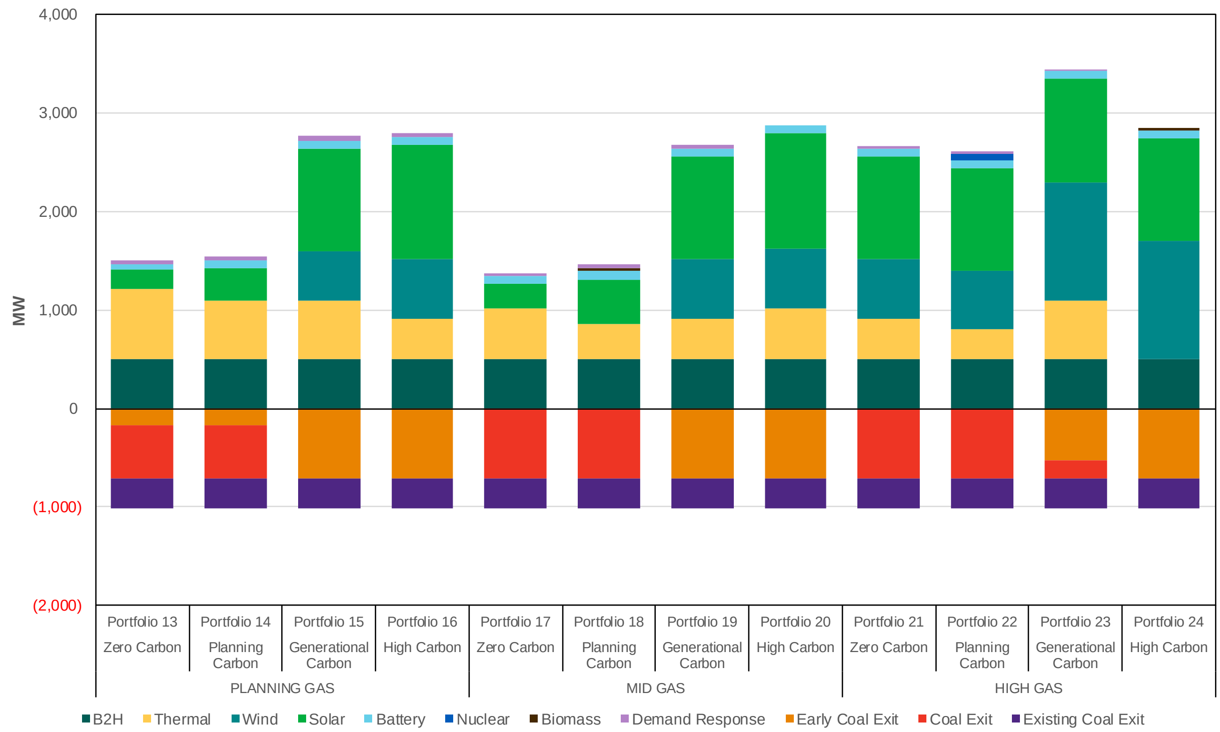

Figure 8.4 WECC-optimized portfolios 13 through 24 (B2H portfolios), capacity additions/reductions (MW)

Manually Built Portfolios

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 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.

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 rate (% of investment)	0.49%
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)	0.03%
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 price forecast than under a High Gas and High Carbon 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	$6,278,713	$7,153,154	$8,736,678	$9,802,332
Portfolio 2	$6,282,756	$7,174,552	$8,577,425	$9,695,929
Portfolio 3	$6,868,094	$7,341,418	$8,188,333	$8,757,756
Portfolio 4	$6,909,873	$7,351,820	$8,172,789	$8,709,946
Portfolio 5	$6,407,151	$7,051,991	$8,983,091	$9,967,976
Portfolio 6	$6,295,887	$6,987,393	$8,852,891	$9,853,177
Portfolio 7	$7,230,980	$7,589,273	$8,284,393	$8,678,643
Portfolio 8	$7,086,109	$7,447,426	$8,260,812	$8,684,372
Portfolio 9	$6,626,104	$6,994,787	$8,645,465	$9,326,708
Portfolio 10	$6,866,736	$7,105,974	$8,635,942	$9,196,065
Portfolio 11	$7,867,263	$7,897,257	$8,921,579	$9,057,434
Portfolio 12	$7,700,882	$7,866,914	$8,508,580	$8,662,707
Portfolio 13	$6,276,926	$7,189,464	$8,839,672	$9,941,809
Portfolio 14	$6,281,733	$7,198,597	$8,715,087	$9,879,956
Portfolio 15	$6,748,522	$7,487,819	$8,179,919	$9,014,114
Portfolio 16	$6,674,015	$7,381,746	$8,062,506	$8,860,820
Portfolio 17	$6,339,272	$7,101,059	$9,025,272	$10,126,056
Portfolio 18	$6,371,297	$7,104,072	$9,012,603	$10,082,271
Portfolio 19	$6,985,582	$7,574,547	$8,268,054	$8,931,658
Portfolio 20	$6,679,355	$7,381,868	$8,051,005	$8,841,573
Portfolio 21	$6,472,912	$7,065,637	$8,896,703	$9,815,932
Portfolio 22	$6,505,881	$7,071,269	$8,885,581	$9,795,651

NPV ($ x 1000)	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	High Gas, High Carbon
Portfolio 23	$7,348,046	$7,732,620	$8,633,344	$9,137,650
Portfolio 24	$6,957,458	$7,665,019	$8,391,091	$9,237,524

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.

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, 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.

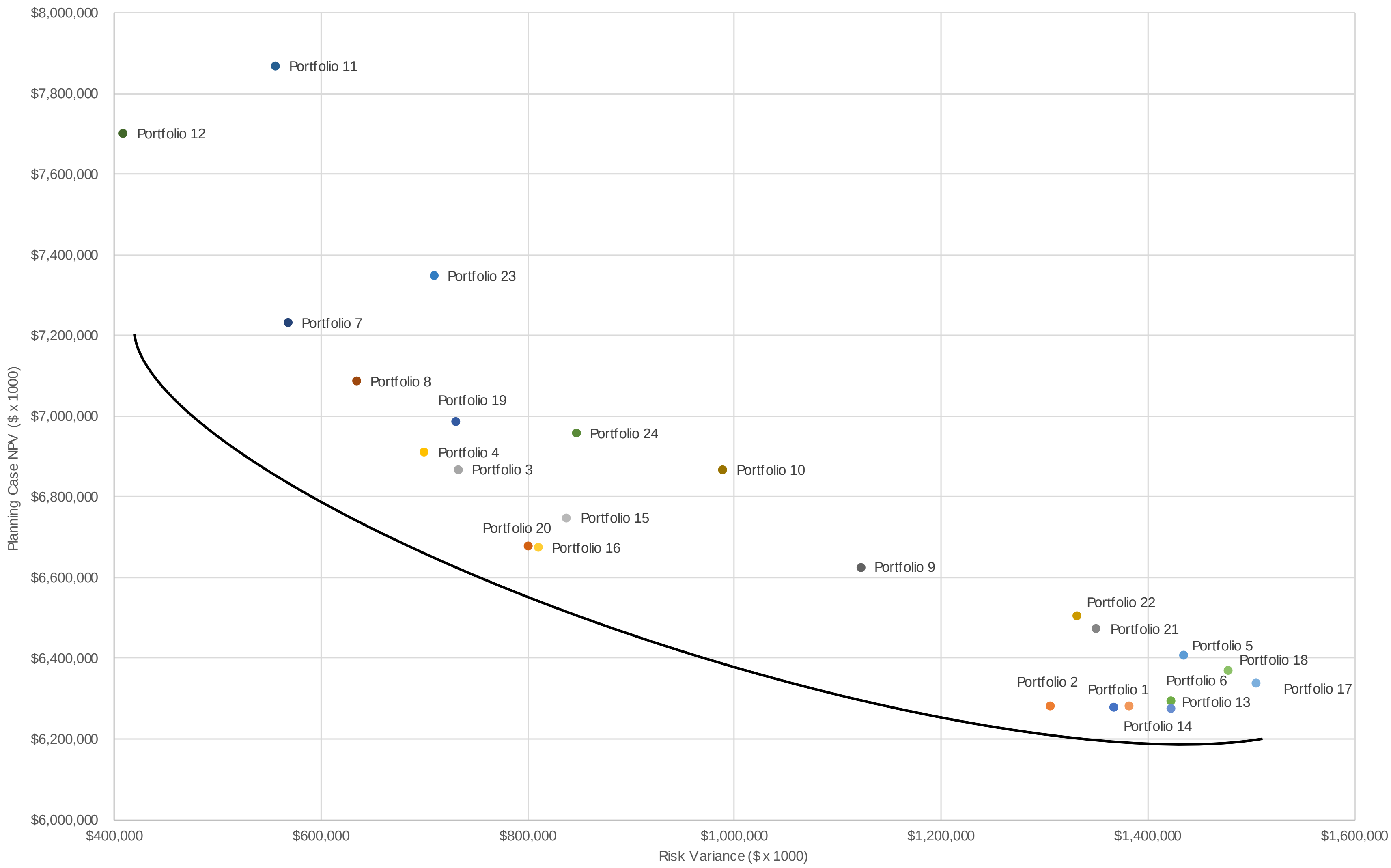

Figure 9.1 **NPV cost versus cost variance**

As indicated in Table 8.5, the starting point of the manual optimization process was determined from the following WECC-optimized portfolios:

- Planning Gas, Planning Carbon: P(1), P(2), P(13), P(14)
- Planning Gas, High Carbon: P(3), P(4), P(15), P(16)
- High Gas, 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 different flexibility resources (pumped hydro, biomass, and nuclear instead of natural gas).

Manually Built Portfolios

Manual adjustments focused first on the evaluation of Jim Bridger coal unit exit scenarios. In the following tables, Jim Bridger exit dates for the first three scenarios 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	Varied*
2026	2028	2026	Varied*
2028	2034	2034	Varied*
2030	2034	2034	Varied*

* The Jim Bridger exit timing for Scenario 4 was selected based on learnings from the first three scenarios and gas and carbon assumptions.

The following guiding principles were used in the manual optimization process for the first three scenarios:

- 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:

- 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 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 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 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
PGPC (1)	$6,279,509	$7,426,379	$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
PGPC (4)	$6,279,772	$7,259,024	$8,558,682	$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)	$6,453,111	$7,181,508	$8,242,129	$9,151,410
PGHC (4)	$6,294,814	$7,359,094	$8,091,963	$9,277,557
HGHC (1)	$7,469,519	$7,934,725	$8,635,143	$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 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)

NPV ($ x 1000)	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	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
Portfolio HGHC (1)	$7,465,092	$7,907,690	$8,603,701	$9,153,185
Portfolio HGHC (2)	$7,000,131	$7,508,566	$8,642,228	$9,374,281
Portfolio HGHC (3)	$7,052,572	$7,564,816	$8,632,474	$9,326,503
Portfolio HGHC (4)	$6,918,876	$7,819,991	$8,652,244	$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

The WECC buildout approaches provide a measure of how robust each portfolio 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 each of the four future gas and 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.

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)

NPV ($ x 1000)	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	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
Portfolio HGHC (1)	$7,463,362	$7,916,793	$8,598,742	$9,150,718
Portfolio HGHC (2)	$6,998,401	$7,517,669	$8,637,269	$9,371,814
Portfolio HGHC (3)	$7,050,842	$7,573,919	$8,627,515	$9,324,036
Portfolio HGHC (4)	$6,917,146	$7,829,094	$8,647,285	$9,637,500
Portfolio PGPC B2H (1)	$6,236,327	$7,400,616	$8,087,144	$9,346,611
Portfolio PGPC B2H (2)	$6,264,543	$7,257,096	$8,353,157	$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

The PGPC B2H (1) portfolio outperforms the other portfolios in the planning case (Planning Gas, Planning Carbon) and ranks high in the Planning Gas, High Carbon case. Based on these results, the company is confident that the Preferred Portfolio detailed in Chapter 10 achieves the least-cost, least-risk objective of the 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.

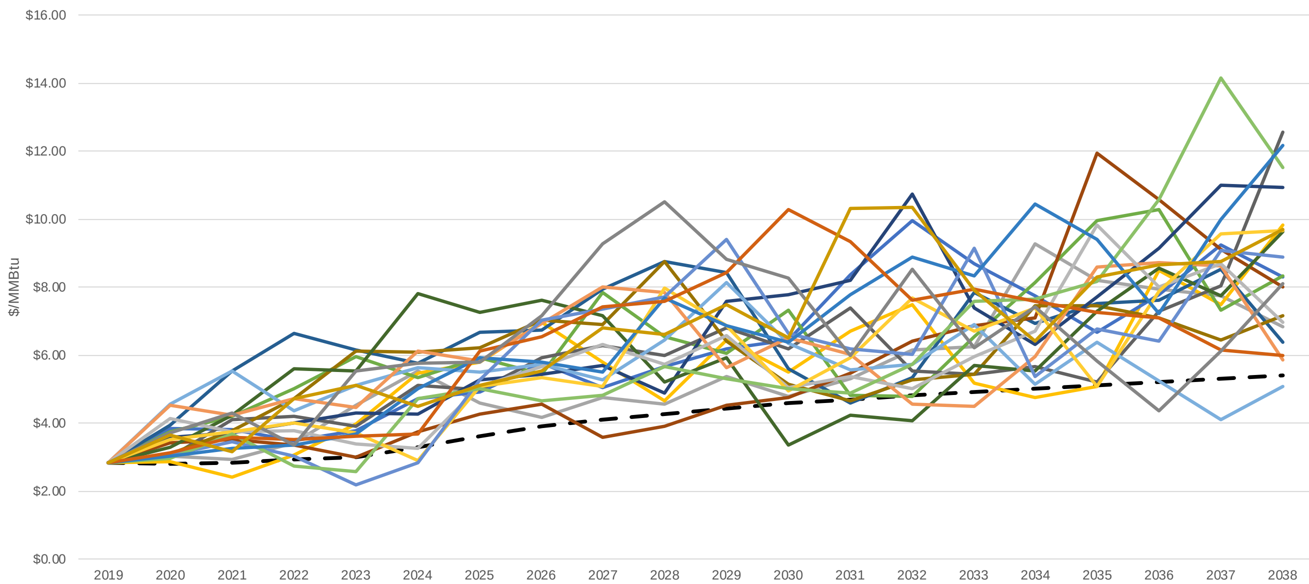

Figure 9.2 Natural gas sampling (Nominal $/MMBtu)

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

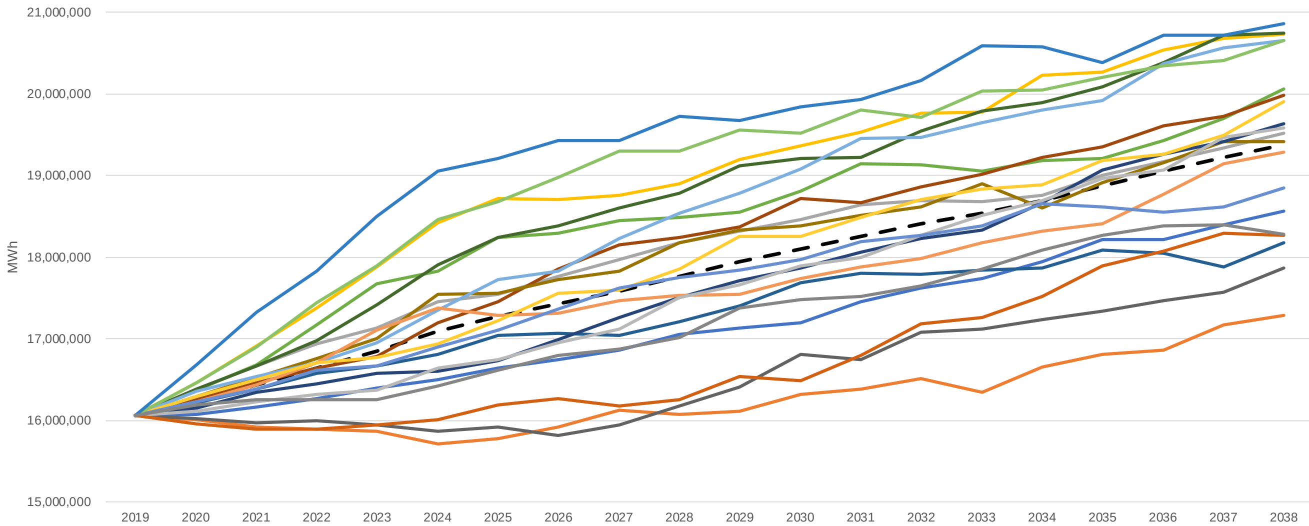

Figure 9.3 Customer load sampling (annual MWh)

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.

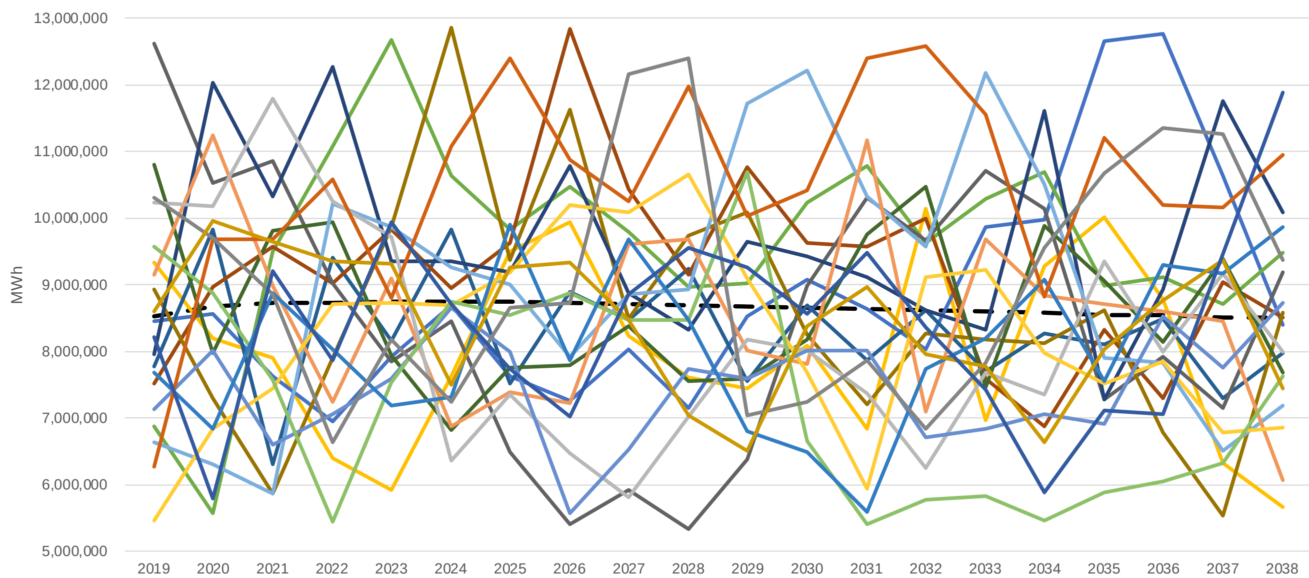

Figure 9.4 Hydro generation sampling (annual MWh)

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.

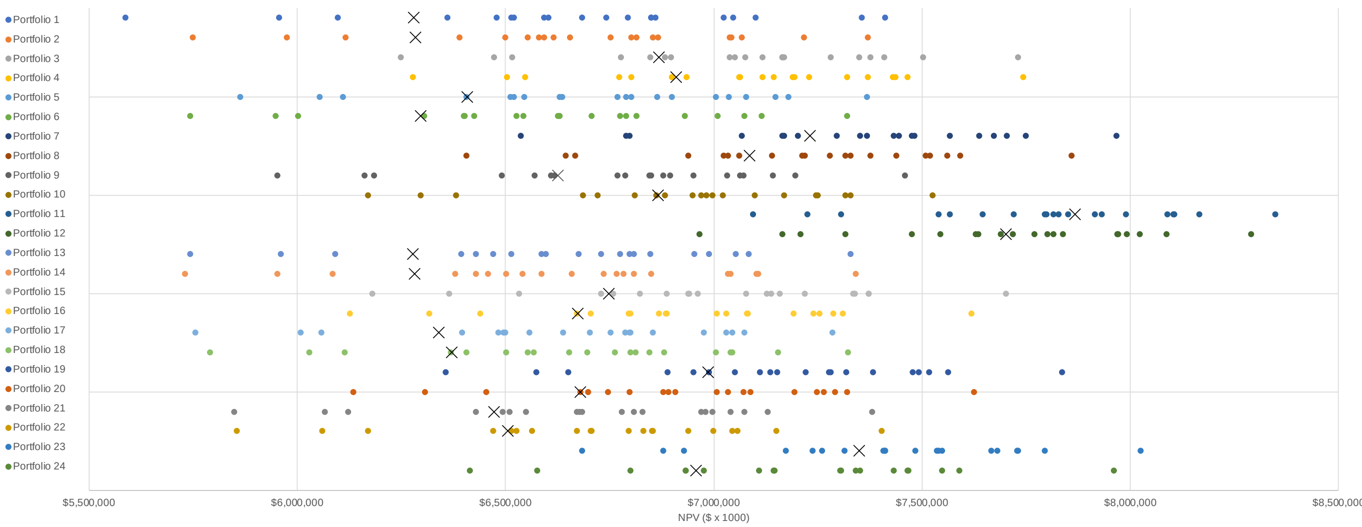

Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2019–2038 ($x 1,000)

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.

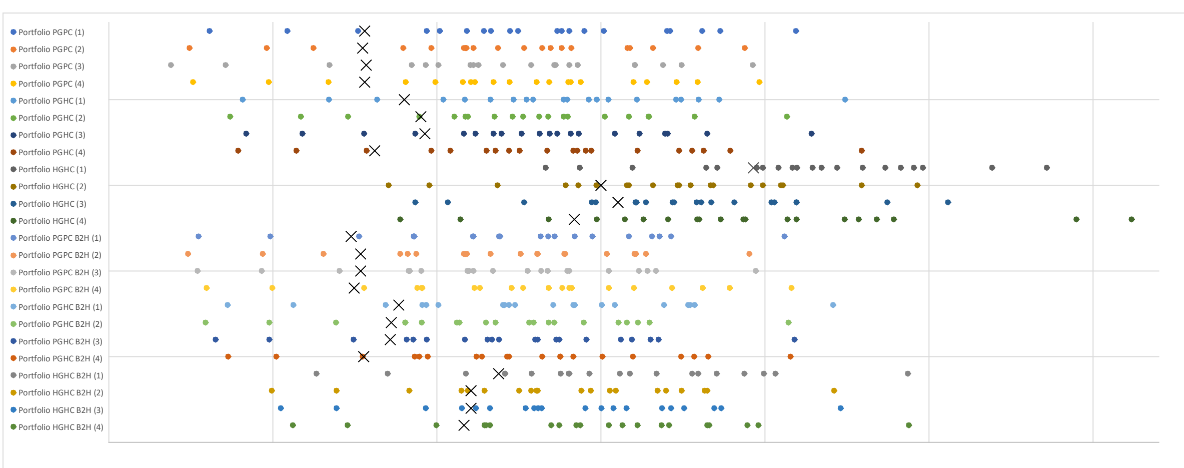

Figure 9.6 Manually built portfolio stochastic analysis with Valmy exit year-end 2022, total portfolio cost, NPV years 2019–2038 ($x 1,000)

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 9.7 and Figure 9.6 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

CO_2 emissions for all 24 portfolios were evaluated during the portfolio cost analysis. The results for all 24 portfolios are shown in Figure 9.7. Figure 9.7 is a stacked column that shows the year-to-year cumulative emissions for each portfolio's projected generating resources.

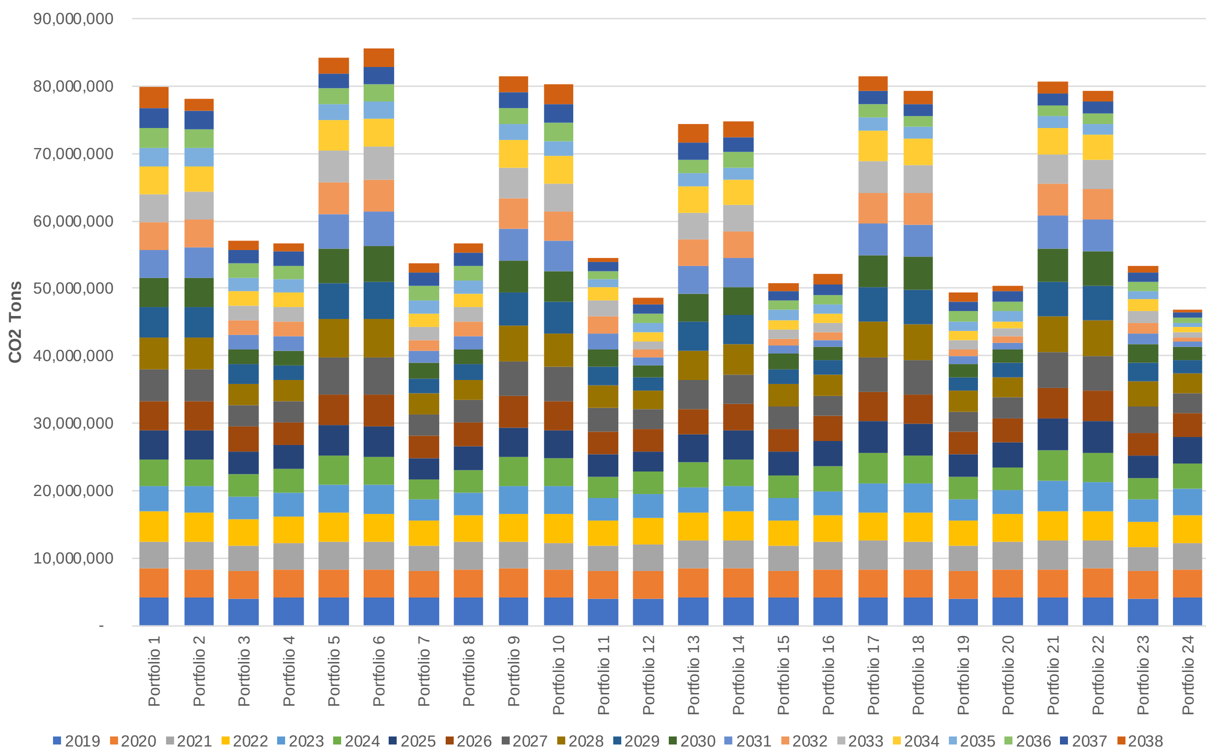

Figure 9.7 Estimated portfolio emissions from 2019–2038

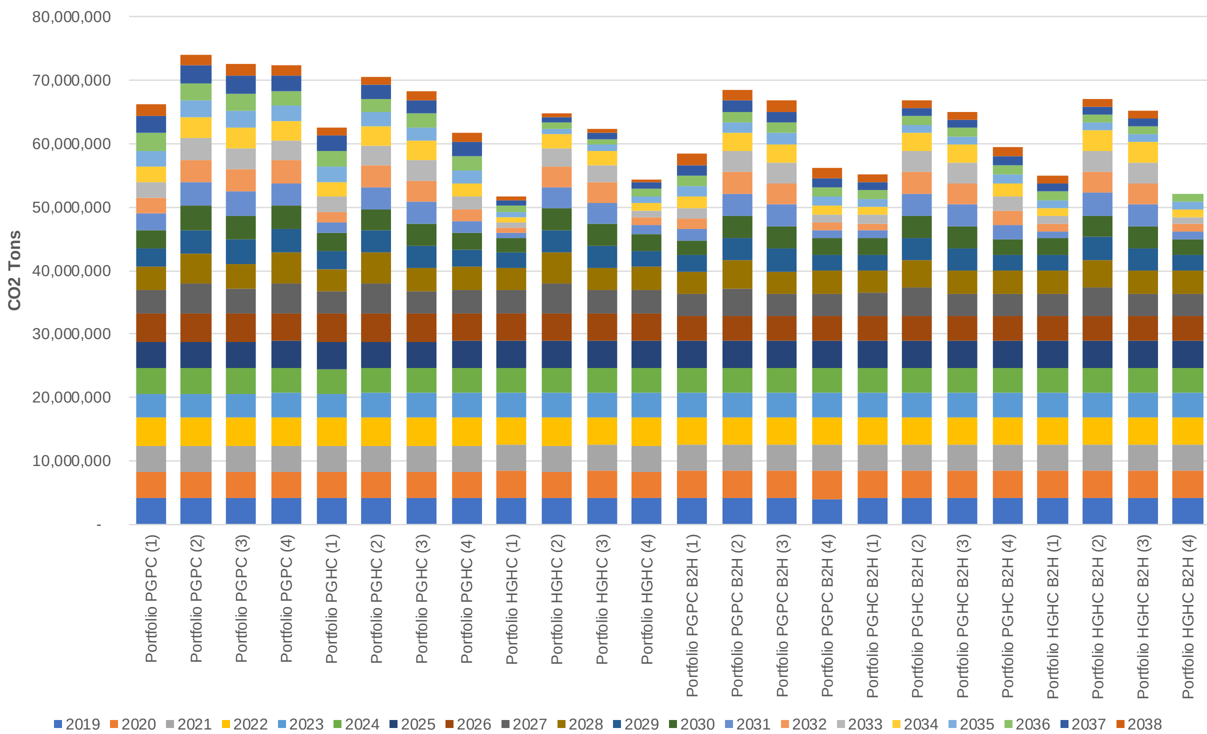

Figure 9.8 Estimated portfolio emissions from 2019–2038—manually built portfolios

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 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 50^{th} percentile forecast to a higher load forecast of 95^{th} percentile.

Ultimately, 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 performing within the industry standard of less than one event per 10 years and will be resource adequate through 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,[22] 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 9.9). 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.

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

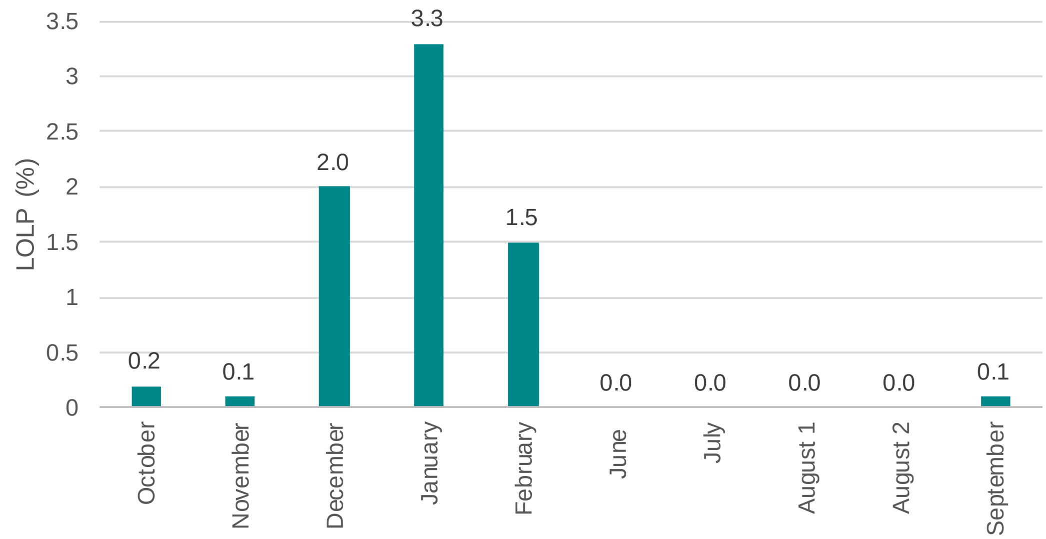

Figure 9.9 LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[23] BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled 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 9.8 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

[23] 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

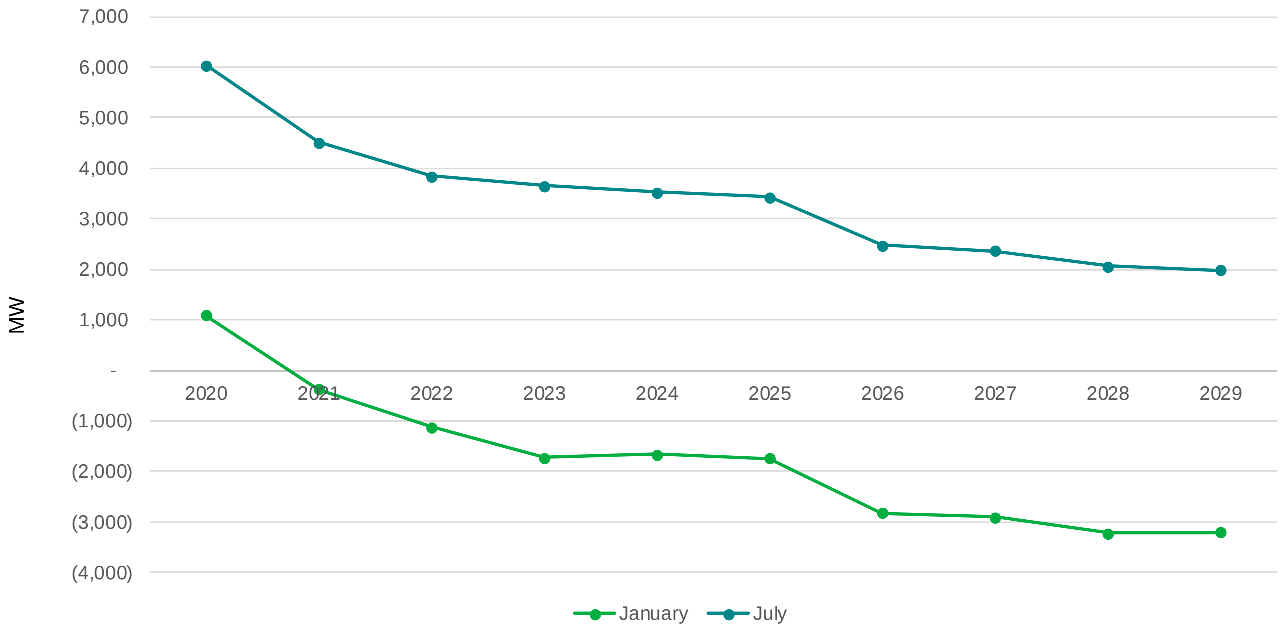

Figure 9.10 BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

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 9.11.

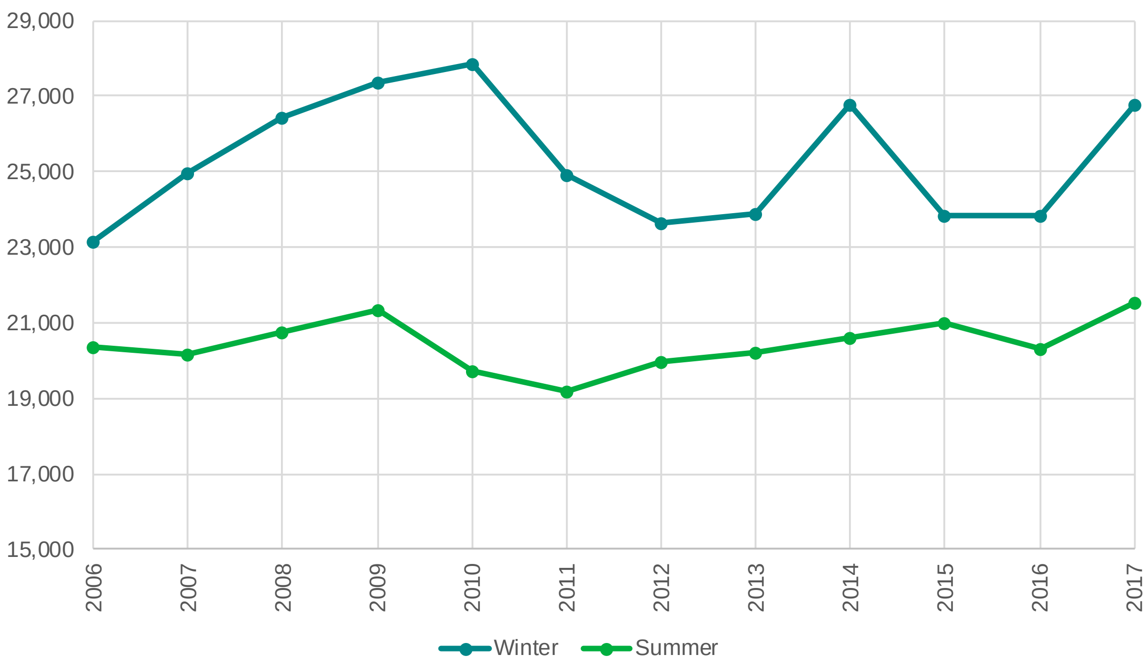

Figure 9.11 Peak coincident load data for most major Washington and Oregon utilities

Figure 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 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 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* was developed under an assumption of planning case natural gas and carbon price forecasts. In terms of nomenclature, the Preferred Portfolio is designated as Portfolio PGPC B2H (1), where the modifying numeral 1 represents the first scenario identified in Table 9.4 (exit from Bridger coal units in 2022, 2026, 2028, and 2030).

Adjustments to the Preferred Portfolio are described in the Manually Built Portfolios section of Chapter 8. The Preferred Portfolio, particularly with the expansion of solar and 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					
2030		40	30	5	-177 (Bridger)
2031	300			5	
2032				5	
2033				5	
2034		40	20	5	
2035		80	20	5	
2036		120	10	5	
2037	55.5			5	
2038	55.5			5	
Nameplate Total	**411**	**400**	**80**	**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 (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 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

Under the Preferred Portfolio in this *Second Amended 2019 IRP*, demand response is added one year earlier than previously identified in the Preferred Portfolio of the *Amended 2019 IRP*, filed in January 2020. Demand response 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 programs.

Action Plan (2020–2026)

Table 10.3 Action Plan (2020–2026)

Year	Action
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.
2020-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
2020–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
2020–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
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.
2022	Exit Valmy Unit 2 by December 31, 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 critical to 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 and thanks the IRPAC members and the public for their contributions 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. The next plan will be filed in 2021. The energy industry is expected to continue 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.

IDAHO POWER
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

JUNE • 2019

APPENDIX A: SALES AND LOAD FORECAST

SAFE HARBOR STATEMENT

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

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2019 Integrated Resource Plan* (IRP). Appendix A includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The above-mentioned forecast covers a 20-year period from 2019 through 2038.

This appendix describes the development of the expected-case monthly average sales forecast. The forecast is Idaho Power's estimate of the most probable outcome for sales growth during the 20- year planning period. In addition, to account for inherent uncertainty in the forecast, additional forecast cases are prepared to test ranges of variability to the expected case.

Economic and demographic (non-weather-related) assumptions are modified to create scenarios for a low and a high economic-related case. By holding weather variability constant, these forecasts test the assumptions of the expected case economic/demographic variables by applying historically-based parameters of growth on both the low and high side of the economic determinants of the expected case forecast.

Economic data in the forecast models is primarily sourced from Moody's Analytics. The national, state, metropolitan service area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area using an in-house historic 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 the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

As economic growth assumptions influence several classes of service growth rates it is important to review several key components. The number of households in Idaho is projected to grow at an annual rate of 1.3 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. Similarly, the number of households in the Boise–Nampa MSA is projected to grow faster than the state of Idaho as well, at an annual rate of 1.6 percent during the forecast period. 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 real retail electricity prices are used to develop load projections.

Scenarios of weather related influence on potential ranges of the expected-case forecast are tested utilizing a probabilistic 70% and 90% distribution of normal weather (temperature and precipitation) applied to the weather assumptions in the expected case. This provides a comparative range of outcome that isolates long-term sustained weather influences on the forecast.

The forecast of the expected-case scenario shows, Idaho Power's system load is forecast to increase to 2,212 average megawatts (aMW) by 2038 from 1,833 aMW in 2019, representing an average yearly growth rate of 1.0 percent over the 20-year planning period (2019–2038).
A similar annual average growth rate in system load is reflected in both weather-related

scenarios (70th-percentile and 90th-percentile). From an annual peak-hour demand perspective, the expected case of the peak demand forecast will grow to 4,388 megawatts (MW) in 2038 from the all-time system peak of 3,422 MW that occurred on Friday, July 7, 2017, at 5:00 p.m. Idaho Power's system peak increases at an average growth rate of 1.2 percent per year over the 20-year planning period (2019–2038) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2018 level of 556,400 customers to nearly 775,000 customers by 2038.

Beyond the weather, climate, economic and demographic assumptions used to drive the expected-case forecast scenario, several additional assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors.

Some examples include conservation influences on the load forecast, including Idaho Power energy efficiency demand side management (DSM) programs, statutory programs, and non-programmatic trends in conservation. These influences are included in the load forecasts. Idaho Power DSM programs are described in detail in Idaho Power's Demand-Side Management 2018 Annual Report, which is incorporated into this IRP document as Appendix B. Idaho Power also recognizes the impact of on-site generation and electric vehicles in its service territory and does include the energy reduction or addition in the long-term sales and load forecast due to their impact. Further discussions of these assumptions are presented in the appropriate section.

Potential risks during the 20-year forecast horizon include major shifts in the electric utility industry (e.g., state and federal regulations and varying electricity prices) which could influence the load forecast. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously.
The alternative sales and load scenarios in Appendix A—Sales and Load Forecast were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

Data describing the historical and projected figures for the sales and load forecast are presented in Appendix A1 of this report.

2019 IRP Sales and Load Forecast

Average Load

The economic and demographic variables driving the 2019 forecast have the impact of increasing current annual sales levels throughout the planning period. The extended business cycle recovery process after the Great Recession in 2008 for the national and service area economy muted load growth post-recession through 2011. However, in 2012, the extended recovery process was evident, and on-balance stronger growth was exhibited in most economic drivers relative to recent history at that time. It is expected that economic conditions return to long-term fundamentals during the 2019 forecast term. Significant factors and considerations that influenced the outcome of the 2019 IRP load forecast include the following:

- Weather plays a primary role in impacting 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 or defined as 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. In support, 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 (2000–2004) 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 use per customer over much of the forecast period. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., demand response is treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in Appendix C—Technical Appendix. Additional impacts from on-site generation customers and electric vehicles are included as well.

- 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 uncertain magnitude of the energy and peak-demand requirements. The expected 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 impact of additional plant investments and associated variable costs of integrating new resources identified in the 2017 IRP preferred portfolio. The two forecasts converge after the 20-year period, although the 2019 IRP price forecast yields higher prices in the near term when compared to the electricity price forecast used to prepare the 2017 IRP sales and load forecast. Retail prices carry an inverse relationship between electricity prices and electricity demand.

Peak-Hour Demands

Average loads, as discussed in the preceding section, are an integral component to the load forecast, as is the impact of the peak-hour demands on the system. Like the sales forecast discussed in the preceding section, the peak models incorporate several peak forecast scenarios based on historical probabilities of peak day temperatures at the 50^{th}, 90^{th}, and 95^{th}-percentiles of occurrence for each month of the year. The peak-hour demands (peaks) are forecasted separately using regressions that are expressed as a function of the sales (average load) forecast as well as the impact of peak-day temperatures, more discussion is provided in forthcoming sections. The peak forecast results and comparisons with previous forecasts differ for many reasons that include the following:

- The all-time system summer peak demand was 3,422 MW (recorded on Friday, July 7, 2017, at 5:00 p.m.). Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m. and matched the previous record peak dated December 10, 2009, at 8:00 a.m.

- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50^{th}, 90^{th}, and 95^{th}-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1988 to 2017 time period (the most recent 30 years).

- The 2019 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

OVERVIEW OF THE FORECAST AND SCENARIOS

The sales and load forecast is constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and special contracts. In conjunction with this load (or sales) forecast, an hour peak-load (peak) forecast was prepared. In addition, several probability cases were developed for the energy and peak forecasts. Assumptions for each of the individual categories, the peak hour impacts, and probabilistic case methodologies are described in greater detail in the following sections.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case average load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts and the resulting derived economic forecast for Idaho Power's service area.

The expected-case average load forecast assumes median temperatures and median precipitation (i.e., there is a 50 percent chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier than median precipitation). Since actual loads can vary significantly depending on weather conditions, alternative scenarios were developed that address load variability due to varying weather conditions.

Illustratively, Idaho Power's maximum annual average load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum annual average load occurs when the opposite of what is described above takes place. In the 70^{th}-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70^{th}-percentile of HDD in wintertime and at the 70^{th}-percentile of CDD in summertime. In the 70^{th}-percentile irrigation load forecast, GDD were assumed to be at the 70^{th}-percentile and precipitation at the 30^{th}-percentile, reflecting drier-than-median weather. The 90^{th}-percentile load forecast was similarly constructed.

For example, the median HDD in December from 1988 to 2017 (the most recent 30 years) was 1,035, at the Boise Weather Service office. The 70^{th}-percentile HDD is 1,065 and would be exceeded in 3 out of 10 years. The 90^{th}-percentile HDD is 1,188 and would be exceeded in 1 out of 10 years. As an example, for a single month, the 100^{th}-percentile HDD (the coldest December over the 30 years) is 1,449, which occurred in December 1990. This same concept was applied in each month throughout the year for the weather-sensitive customer classes: residential, commercial, and irrigation.

Since Idaho Power loads are highly dependent on weather, and the development of the above mentioned two scenarios allows the careful examination of load variability and how it may impact future resource requirements, it is important to understand that the probabilities associated with these forecasts apply to each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. Table 1 summarizes the load scenarios prepared for the 2019 IRP.

Table 1. Average load and peak-demand forecast scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90th Percentile	90%	1 in 10 years	HDD, CDD, GDD, precipitation
70th Percentile	70%	3 in 10 years	HDD, CDD, GDD, precipitation
Expected Case	50%	1 in 2 years	HDD, CDD, GDD, precipitation
Forecasts of Peak Demand			
95th Percentile	95%	1 in 20 years	Peak-day temperatures
90th Percentile	90%	1 in 10 years	Peak-day temperatures
50th Percentile	50%	1 in 2 years	Peak-day temperatures

Results of Idaho Power's weather related probabilistic system load projections are reported in Table 2 and shown in Figure 1.

Table 2. System load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	1,939	2,035	2,140	2,342	1.0%
70th Percentile	1,878	1,970	2,072	2,267	1.0%
Expected Case	1,833	1,923	2,022	2,212	1.0%

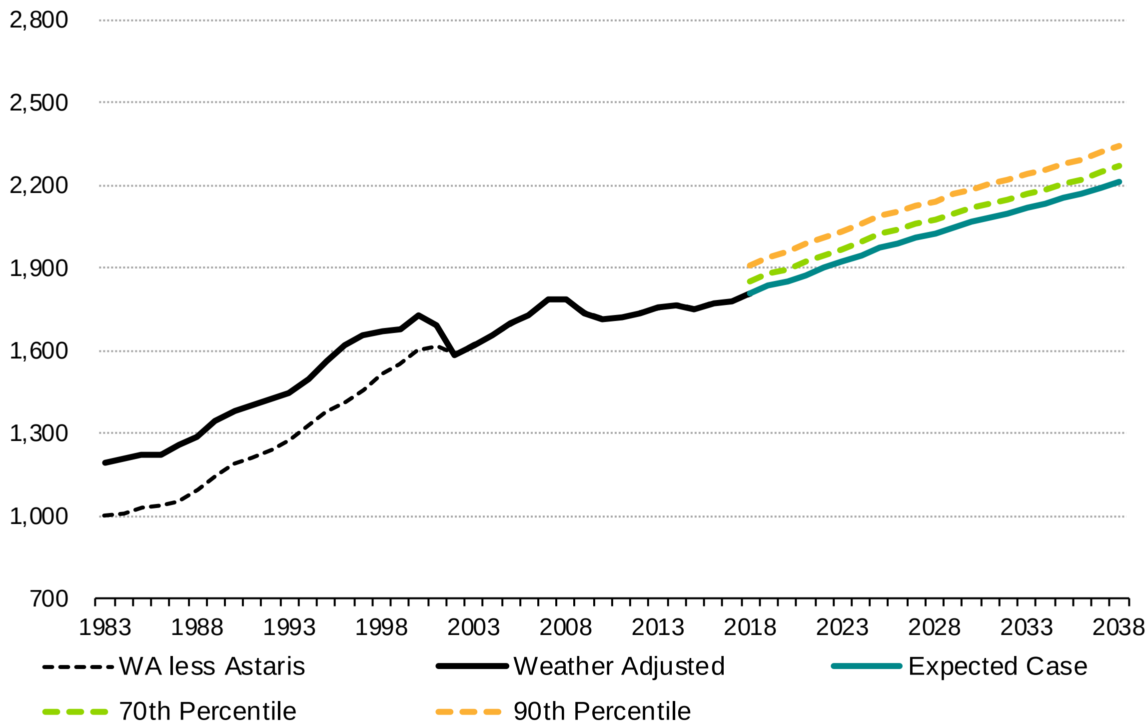

Figure 1. Forecast system load (aMW)[1]

Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period.

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared based on the expected case forecast. The forecasts provide a range of possible load growth rates for the 2019 to 2038 planning period due to high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1994–2018).

Of the three scenarios 1) the expected forecast is the median growth path, 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1994–2018).

From the above methodology, two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported

[1] The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

in Table 3. The probability of exceeding the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10 percent probability the actual growth rate will exceed the growth rate projected in the high scenario; additionally, it can be inferred that for the stated periods there is an 80 percent probability the actual growth rate will fall between the low and high scenarios.

The second probability estimate, the probability of occurrence, indicates the likelihood the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26 percent probability the actual growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon.

Table 3. Forecast probabilities

Probability of Exceeding				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	90%	90%	90%	90%
Expected Case	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts.

Results of Idaho Power's economic scenario probabilistic system load projections are reported in Table 4 and shown in Figure 2. The expected-case system load-forecast growth rate averages 1.0 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.5 percent per year throughout the forecast period. The high scenario projects a load growth of 1.4 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Low	1,789	1,822	1,879	1,986	0.5%
Expected	1,833	1,923	2,022	2,212	1.0%
High	1,878	2,030	2,189	2,465	1.4%

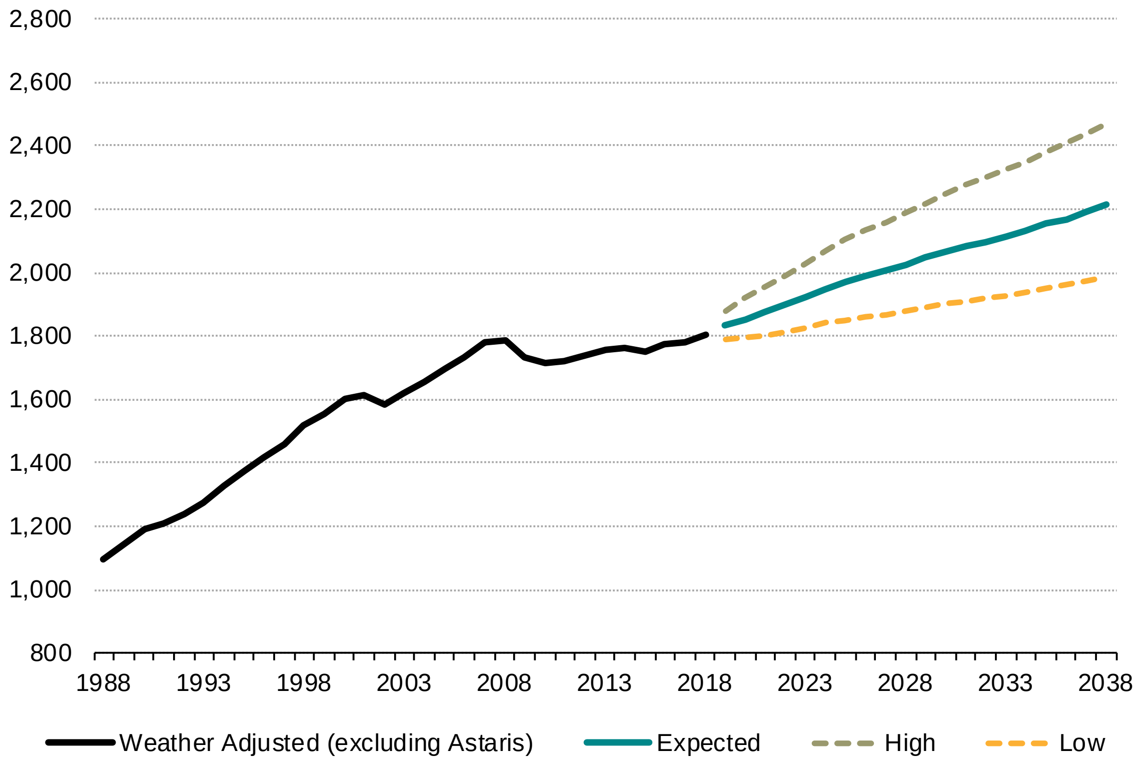

Figure 2. Forecast system load (aMW)

COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm off-system contracts.

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.0 percent per year from 2019 to 2038. Company system load projections are reported in Table 2 and shown in Figure 1.

In the expected-case forecast, the company system load is expected to increase from 1,833 aMW in 2019 to 2,212 aMW in 2038, an average annual growth rate of 1.0 percent. In the weather sensitive scenarios, the 70th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,878 aMW in 2019 to 2,267 aMW by 2038, and increase from 1,939 aMW in 2019 to 2,342 aMW, respectively. All represent an average growth rate of 1.0 percent per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,789 aMW in 2019 to 1,986 aMW in 2038, an average annual growth rate of 0.5 percent and in the high case from 1,838 aMW to 2,465 aMW, an average annual growth rate of 1.4 percent (Table 2).

The system load, excluding Astaris, portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new significant large-load customer on system load. As noted previously, the forecast excludes any such speculative large-load customers.

Accompanied by an outlook of economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term, firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 3. Residential sales are forecast to be about 23 percent higher in 2038, gaining 1.2 million MWh over 2019. Commercial sales are also expected to be 24 percent higher, or 1.0 million MWh, then in 2019, followed by industrial (11 percent higher, or 0.3 million additional MWh) and irrigation (16 percent higher in 2038 than 2019).

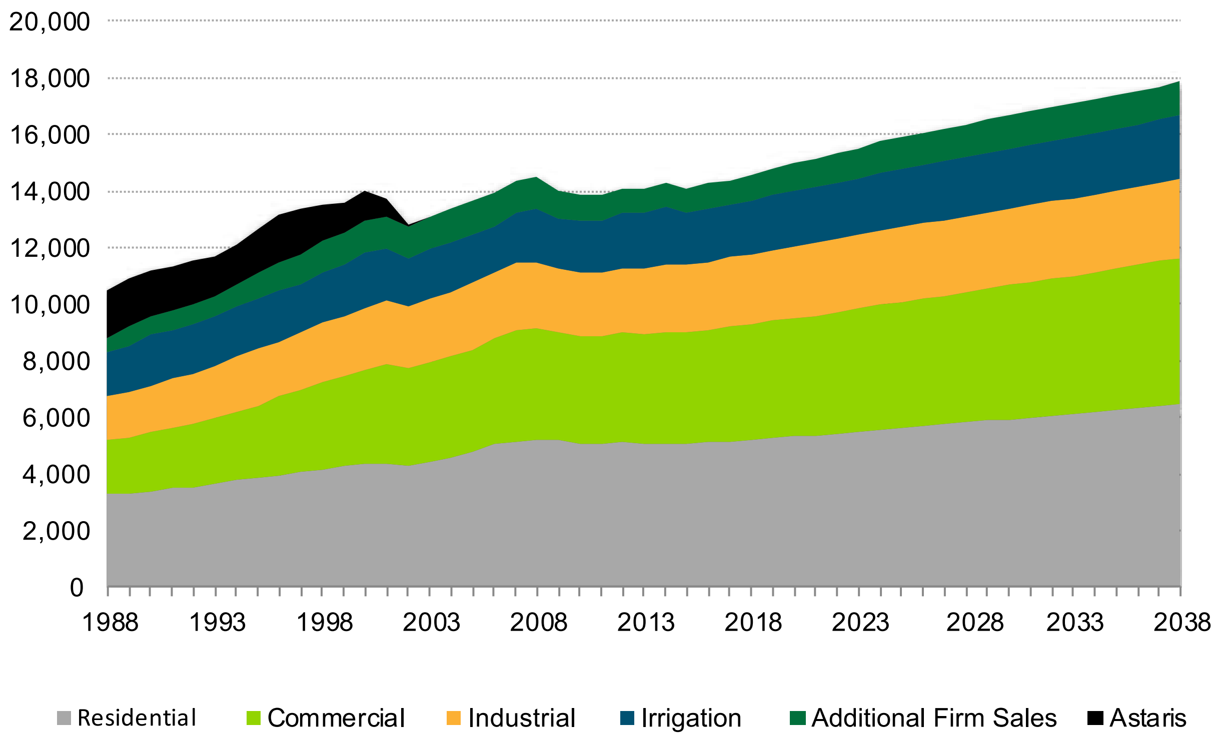

Figure 3. Composition of system company electricity sales (thousands of MWh)

COMPANY SYSTEM PEAK

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

Seasonal Peak Forecast

Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June, July or August, which coincides with cooling load and irrigation pumping demand. The summer peak is reflective of the annual peak for the Company.

The all-time system summer peak demand was 3,422 MW, recorded on Friday, July 7, 2017, at 5:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

The 95th-percentile forecast, the system summer peak load is expected to increase from 3,634 MW in 2019 to 4,544 MW in 2038. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,610 MW in 2019 to 4,519 MW in 2038. Finally, the 50th-percentile, or expected case, the system summer peak load increases from 3,479MW in 2019 to 4,388MW in 2038. All of which represent an average summer peak growth rate of 1.2 percent per year over the planning period (Table 5).

Table 5. System summer peak load growth (MW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
95th Percentile	3,634	3,832	4,073	4,544	1.2%
90th Percentile	3,610	3,808	4,048	4,519	1.2%
50th Percentile	3,479	3,677	3,918	4,388	1.2%

The three scenarios of projected system summer peak loads are illustrated in Figure 4. Much of the variation in peak load is due to weather conditions. Note that unique economic events have occurred, as an example in the summer of 2001 the summer peak was dampened by a nearly 30-percent curtailment in irrigation load due a voluntary load reduction program.

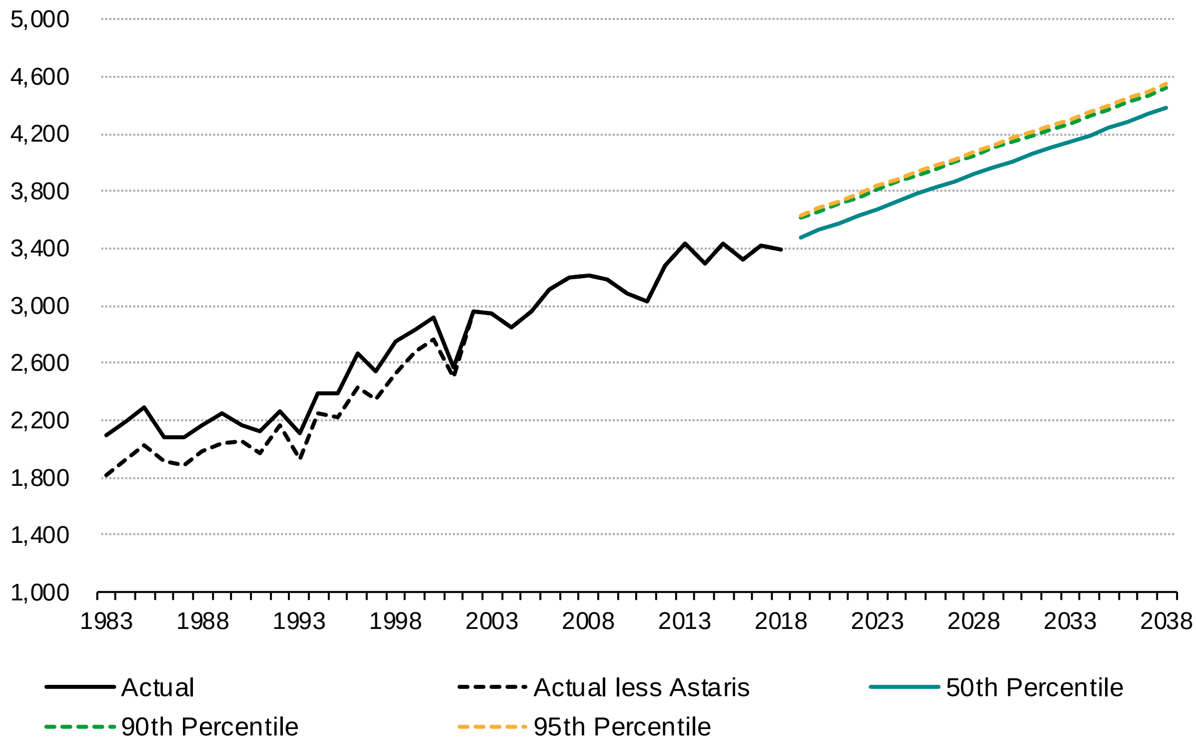

Figure 4. Forecast system summer peak (MW)

As of December 31, 2018, the all-time system winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. and matched on January 6, 2017, at 9:00 a.m. As shown in Figure 5, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 5 illustrates the higher variability associated with winter peak-day temperatures.

In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,636 MW in 2019 to 3,058 MW in 2038, an average growth rate of 0.8 percent per year over the planning period. In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,549 MW in 2019 to 2,998 MW in 2038, an average growth rate of 0.9 percent per year over the planning period. In the 50th-percentile, or expected case forecast, the system winter peak load is expected to increase from 2,390MW in 2019 to 2,887 MW in 2038, an average growth rate of 1.0 percent per year over the planning period. This data is represented in Table 6 below as well as the three scenarios of projected system winter peak load are illustrated in Figure 5.[2]

Table 6. System winter peak load growth (MW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
95th Percentile	2,636	2,735	2,848	3,058	0.8%
90th Percentile	2,549	2,648	2,761	2,998	0.9%
50th Percentile	2,390	2,500	2,635	2,887	1.0%

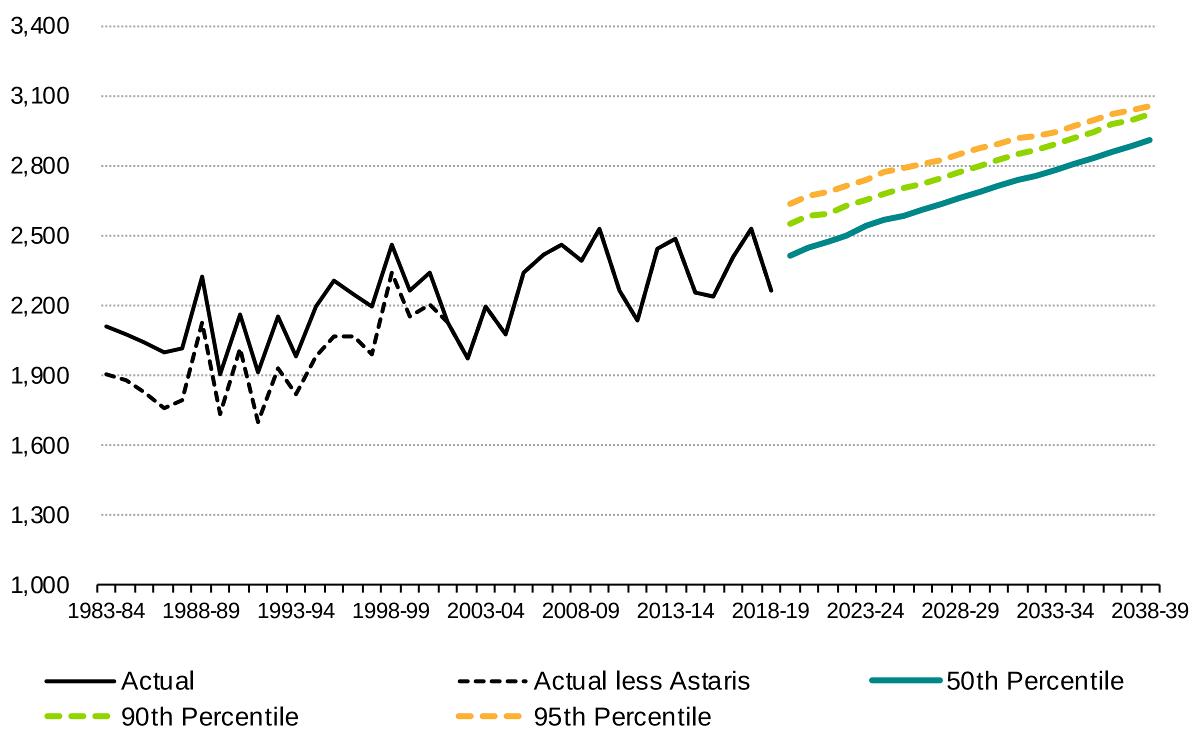

Figure 5. Forecast system winter peak (MW)

Combining the historic relationship of summer and winter peaks as depicted in Figure 6 the growth in the summer peak over the past several decades in Idaho Power's service territory has been much stronger with an increased presence of cooling load in the peak summer months.

[2] Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1988 to 2017 time period (the most recent 30 years).

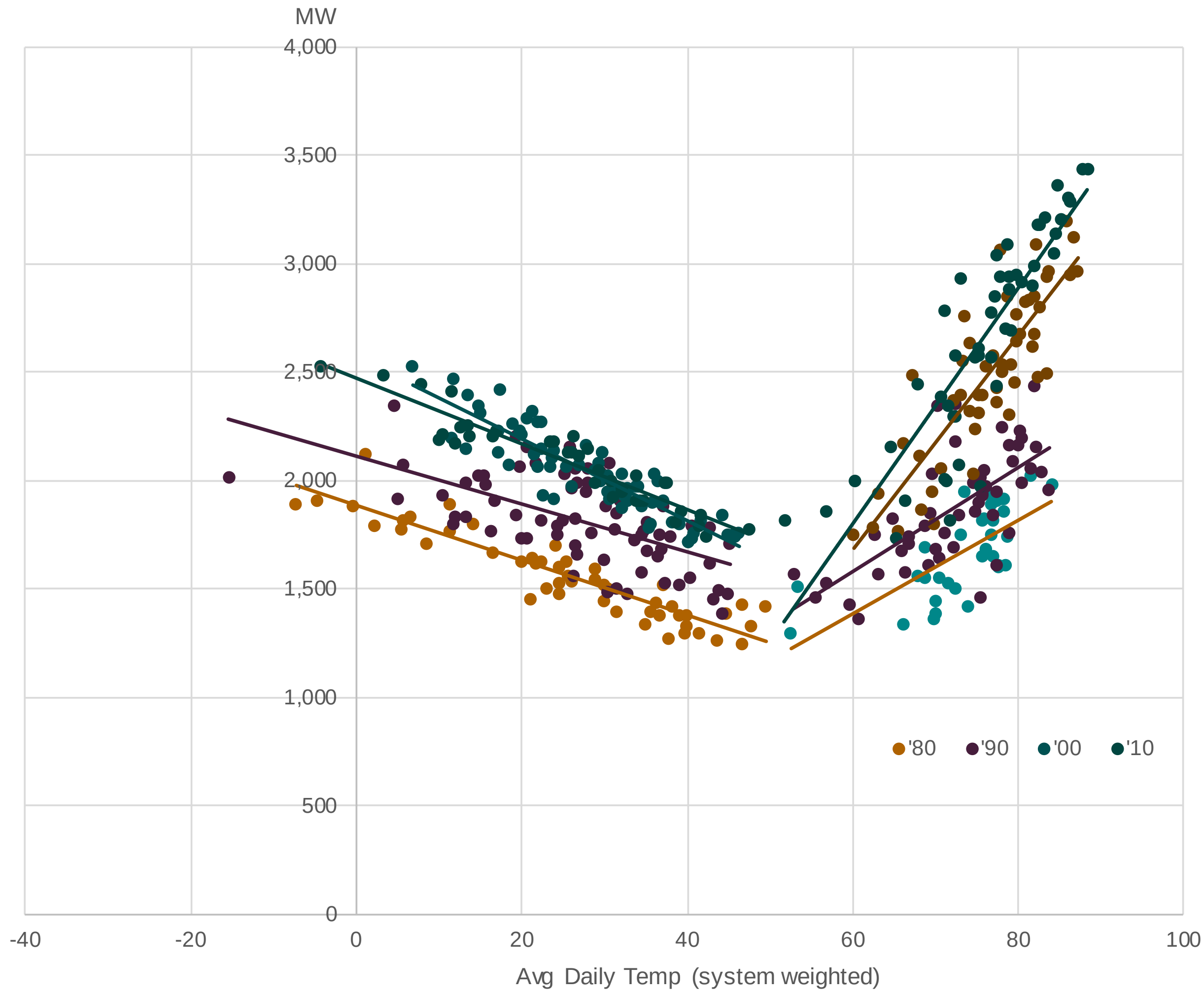

Figure 6. Idaho Power monthly peaks (MW)

Additionally, note the 2019 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

Peak Model Design

Peak-hour demands are integral components to the Company's system planning. Peak-hour demands are forecast using a system of 12 regression equations, one for each month of the year. For most monthly models the regressions are estimated using 25 years of historical data, however, the estimation periods vary. The peak-hour forecasting regressions express system peak-hour demand as a function of calendar sales (stated in average megawatts) as well as the impact of peak-day temperatures, real electricity prices, and in some months precipitation. The contribution to the system peak of the Company's three special contract customers is determined independently, using historical coincident peak factors, and then added to determine the system peak.

The forecast of average peak-day temperatures is a key driver of the monthly system peak models. The normal average peak-day temperature drivers are calculated over the 1988 to 2017 period (the most recent 30 years). In addition, the peak model develops peak-scenarios based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th percentiles of occurrence for each month of the year.

Note the summertime (June, July, and August) system peak regression models were re-specified to account for the upward trend in weighted average peak-day temperatures over time.
The trendlines were fitted to the historical weighted average peak-day temperatures and then projected through the end of the forecast period, the year 2038. These are added as explanatory variables in the summertime regression models. The addition of these variables resulted in models that better fit the actual historical summertime system peaks.

Class Sales Forecasts

Residential

The expected-case residential load is forecast to increase from 601 aMW in 2019 to 742 aMW in 2038, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 621 aMW in 2019 to 769 aMW in 2038, an average annual compound growth rate of 1.1 percent, matching the expected-case residential growth rate (1.1 percent average annual growth). The residential load forecasts are reported in Table 7 and shown in Figure 7.

Table 7. Residential load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	649	680	718	806	1.1%
70th Percentile	621	650	685	769	1.1%
Expected Case	601	628	662	742	1.1%

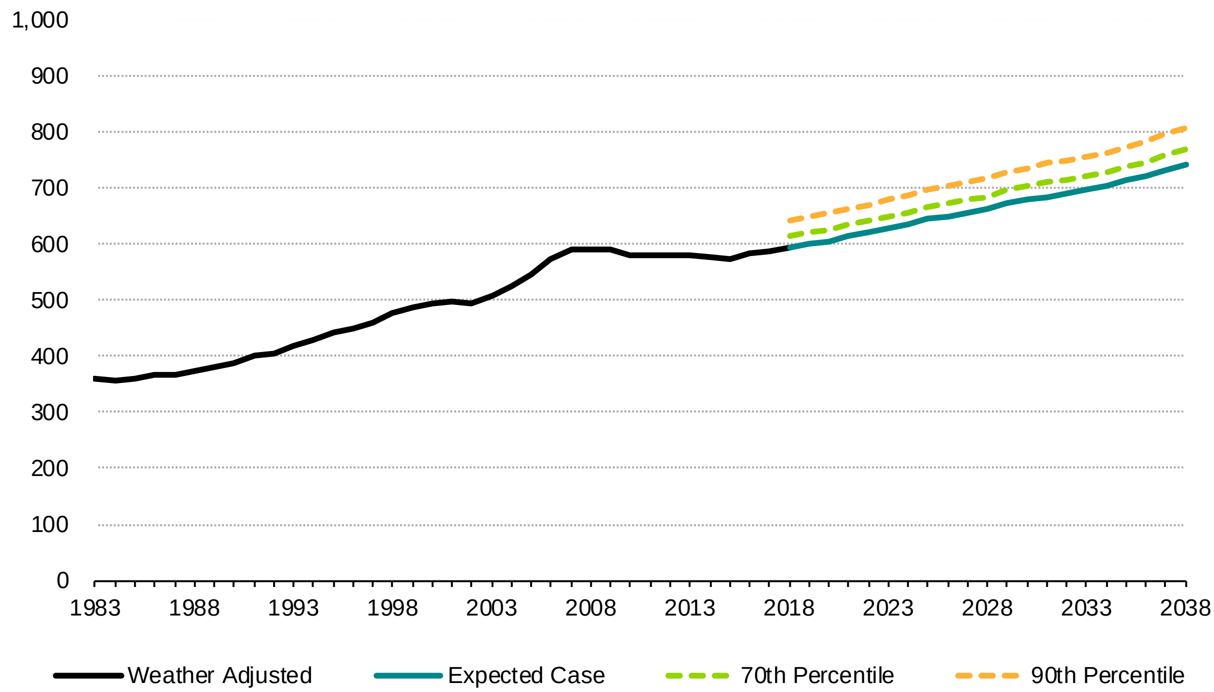

Figure 7. Forecast residential load (aMW)

Sales to residential customers made up 31 percent of Idaho Power's system sales in 1988 and 36 percent of system sales in 2018. The number of residential customers is projected to increase to approximately 649,000 by December 2038.

The average sales per residential customer increased to nearly 14,850 kilowatt-hours (kWh) in 1980 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—nearly 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices in those years combined with a weak national and service area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize through 2007. However, conservation efforts places downward pressure on residential use per customer since that point. This trend is expected to continue, ranging at an approximate decline of up to 0.5 percent–1.0 percent per year, as the average sales per residential customer are expected to decrease to approximately 10,100 kWh per year by 2038. Average annual sales per residential customer are shown in Figure 8.

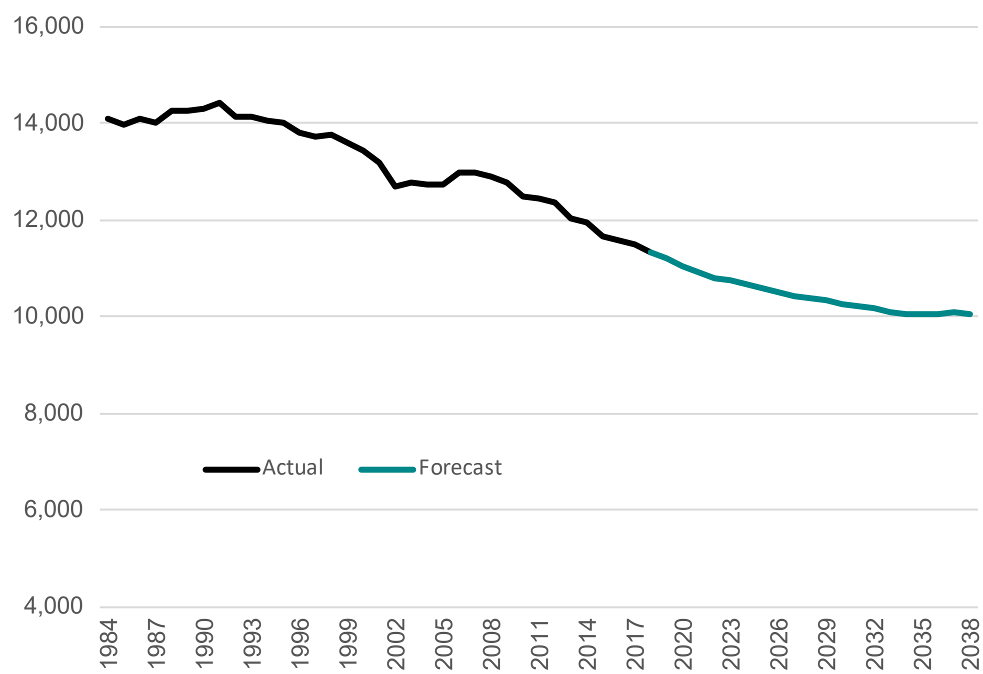

Figure 8. Forecast residential use per customer (weather-adjusted kWh)

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' forecast of county housing stock and demographic data. The residential-customer forecast for 2019 to 2038 shows an average annual growth rate of 1.7 percent as shown in Figure 9.

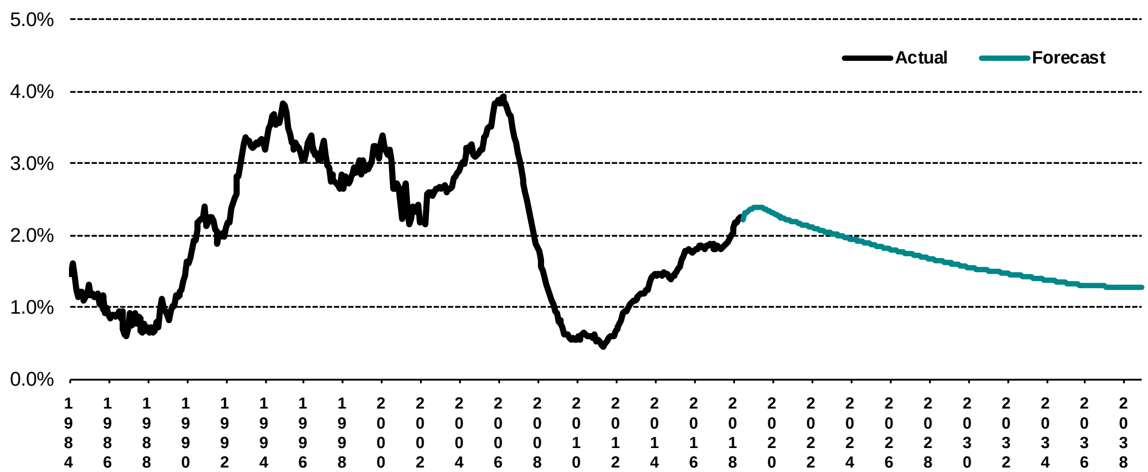

Figure 9. Residential customer growth rates (12-month change)

Final sales to residential retail customers is an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); historic energy efficiency trends in Idaho Power's residential customer base; saturation and replacement cycle of appliances; the number of service-area households; the real price of electricity; and the real price of natural gas to name a few. A general schematic of the forecasting methodology used in Idaho Power's residential sales forecast is provided in Figure 10.

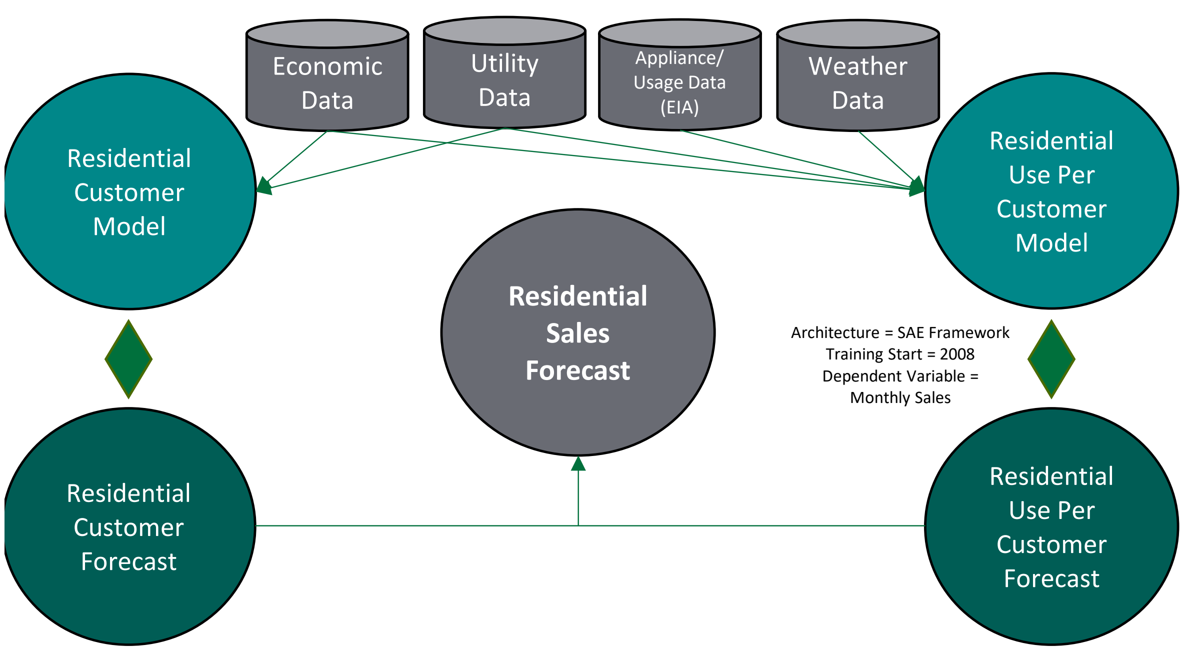

Figure 10. Residential sales forecast methodology framework

Commercial

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Additional customer types associated with this category include small general-service on-site generation, customer energy production net-metering, unmetered general service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

Within the expected-case scenario, the commercial load is projected to increase from 473 aMW in 2019 to 587 aMW in 2038 (Table 8). The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 479 aMW in 2019 to 595 aMW in 2038. The commercial load forecast scenarios are illustrated in Figure 11.

Table 8. Commercial load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	488	512	542	607	1.2%
70th Percentile	479	503	533	595	1.1%
Expected Case	473	496	525	587	1.1%

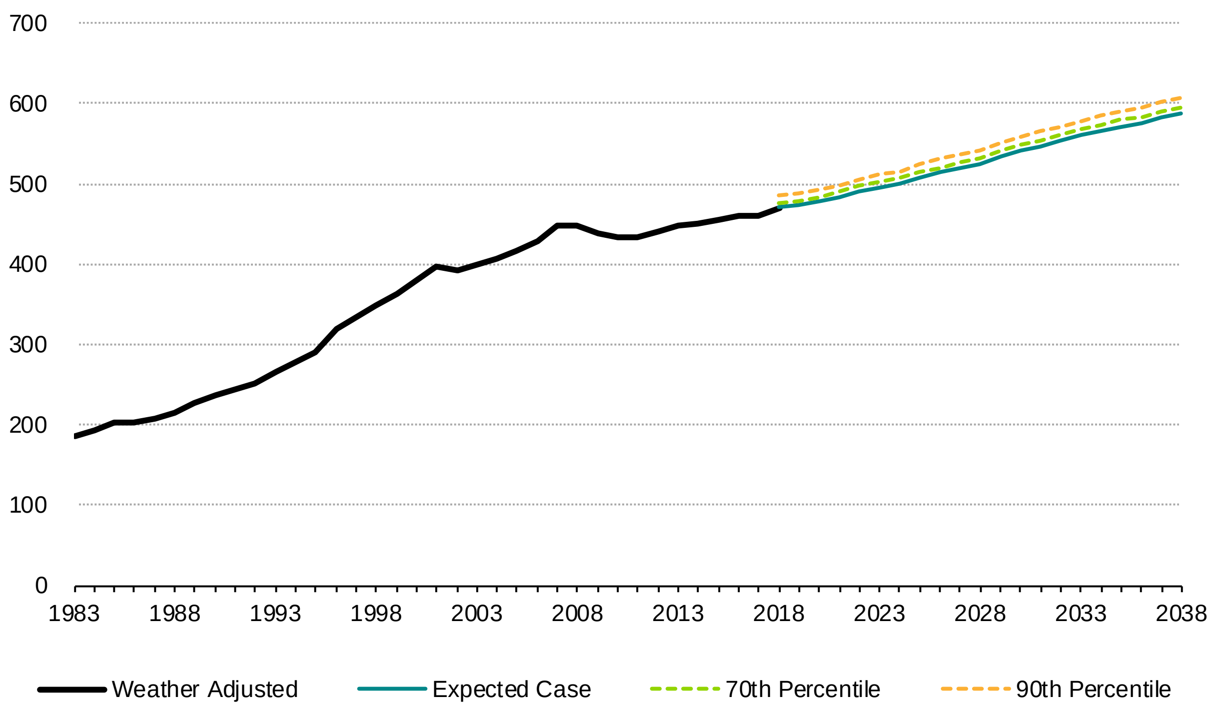

Figure 11. Forecast commercial load (aMW)

With a customer base of nearly 72,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to large manufacturers. Due to this diversity in load intensity and use, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 12 shows the breakdown of the categories and their relative sizes based on 2018 billed energy sales.

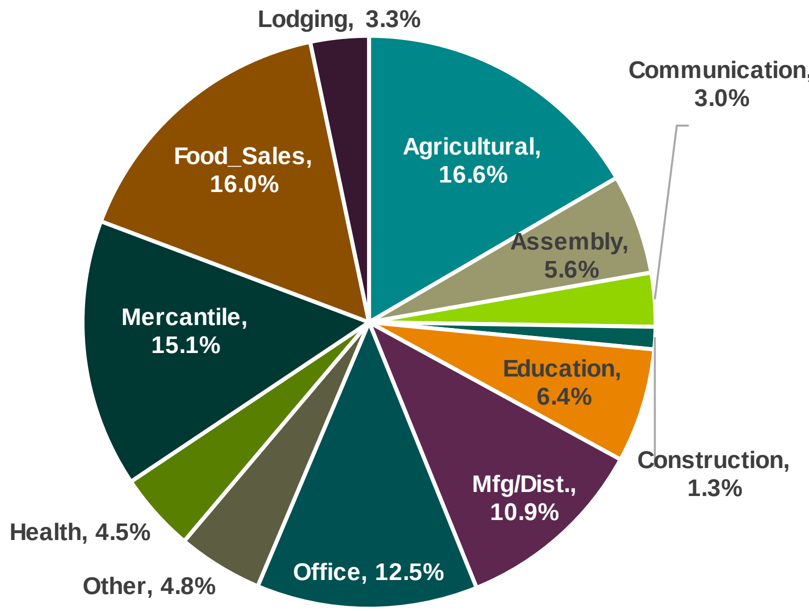

Figure 12. Commercial building share—energy bills

As indicated in Figure 12, agricultural-related, food sales, and the retail goods and service providers of the mercantile category represent nearly half of the sector. Recent trends in the sector show that mercantile growth has moderated. This moderation is primarily due to customer consolidation, growth in internet-based sales, energy efficient retrofitting, and new-construction technology implementation (particularly in the area of lighting). Categories showing significant growth over the past five years are reflective of the changing profile of economic and demographic growth in the service territory. Residential growth has led to a construction boom that has seen construction grow by 17 percent, and the residential profile of older customers has helped to push health care growth to 6 percent. Agricultural and manufacturing operations continue to migrate and flourish with growth rates of 9 percent and 6 percent respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.7 percent, reaching approximately 100,000 customers by December 2038.

In 1988, customers in the commercial category consumed approximately 18 percent of Idaho Power system sales, growing to 28 percent by 2018. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 13 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 13 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, nonetheless it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,575 kWh and has declined at approximately 0.9 percent compounded annually to 2018. The UPC is forecast to decrease at an annual rate of 0.5 percent over the planning period. For this category, common elements that drive use down include increases in business-cycle recessions, adoption of energy efficiency technology, and electricity prices.

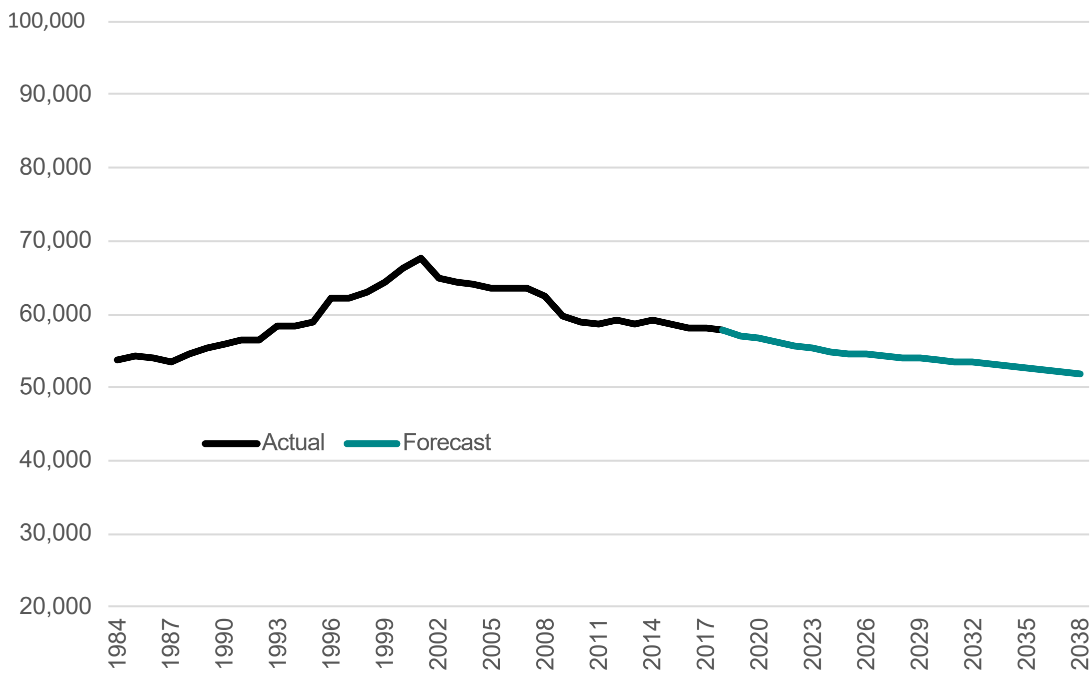

Figure 13. Forecast commercial use per customer (weather-adjusted kWh)

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2018 UPC for each segment relative to the 2011 UPC. A value greater than 100 percent indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 13 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

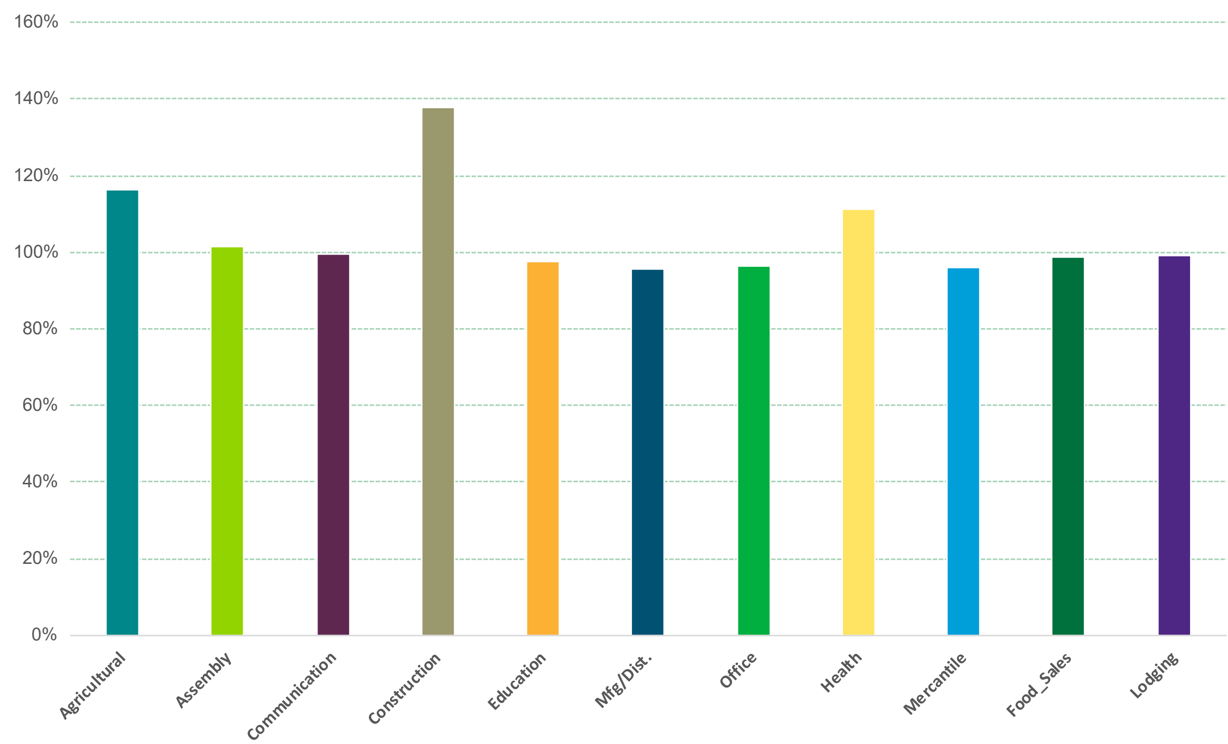

Figure 14. Commercial categories UPC, 2018 relative to 2011

Energy efficiency implementation is a large determinant in UPC decline over time. In the commercial sector, the primary DSM technology impact has come from lighting. The categories of mercantile and office are particularly dominant in this implementation as indicated by the UPC trend. Faster growing categories, such as healthcare tend to show positive UPC trends. Other influences on UPC include differences in price sensitivity, sensitivity to business cycles and weather, and degree and trends in automation. In addition, category UPC can vary when a customer's total use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category. Due to tariff migration, which occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial), the forecast models aggregate the energy use of these two schedules to ensure continuity in the dependent variable.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the category. Typical variables include weather: HDD (wintertime); CDD (summertime); specific industry growth characteristics and outlook; service-area demographics such as households, employment, small business conditions; the real price of electricity; and energy efficiency adoption.

INDUSTRIAL

The industrial category is comprised of Idaho Power's large power service (Schedule 19) customers requiring monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. The category name "Industrial" is reflective of load requirements and not necessarily indicative of the industrial nature of the customers' business.

In 1980, Idaho Power had about 112 industrial customers, which represented about 12 percent of Idaho Power's system sales. By December 2018, the number of industrial customers had risen to 117, representing approximately 17 percent of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration from and to the commercial class as dictated by the tariff rules. However, generally speaking, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 284 aMW in 2019 to 315 aMW in 2038, an average annual growth rate of 0.6 percent (Table 9). To a large degree, industrial load variability is not associated with weather conditions as is the case with residential, commercial, and irrigation; therefore, the forecasts in the 70th- and 90th-percentile weather scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 15.

Table 9. Industrial load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Expected Case	284	296	305	315	0.6%

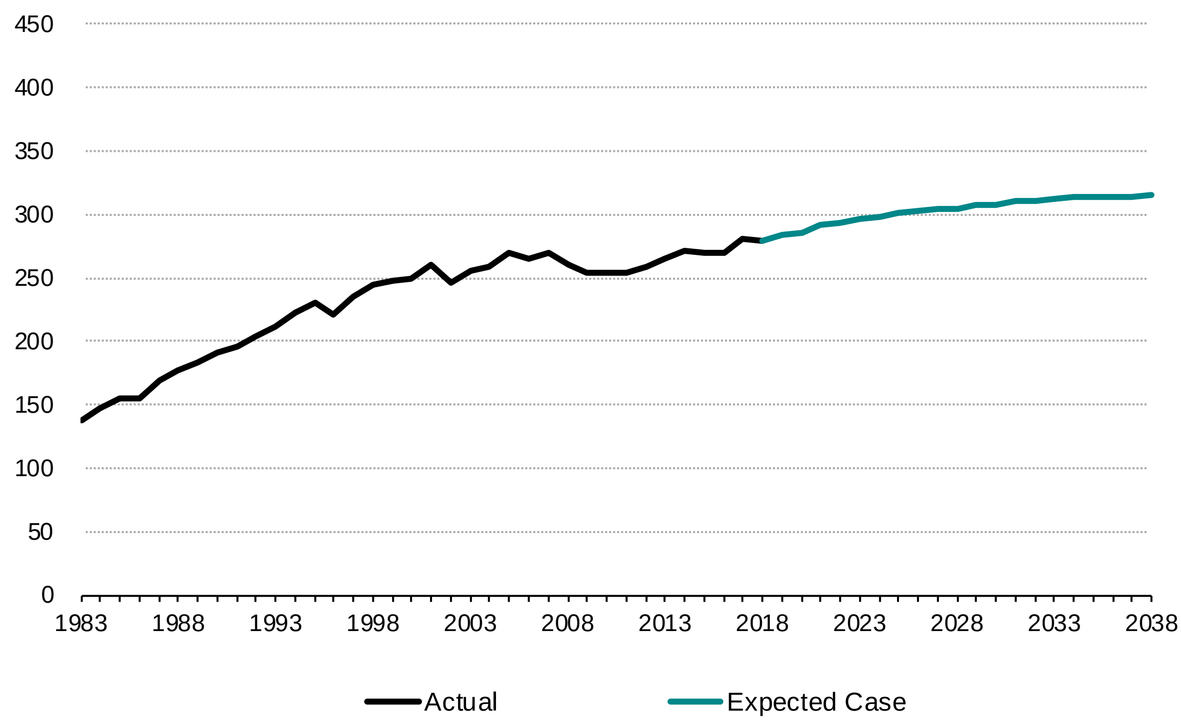

Figure 15. Forecast industrial load (aMW)

As discussed previously the load growth variability is impacted by both economic, non-weather factors, and the impacts of DSM. In developing the forecast, customer-specific DSM implementation is isolated as DSM varies significantly by customer, and the actual energy use is adjusted to remove the impacts of DSM to optimize the causal influence of non-DSM causal variables. The history and forecast of DSM is provided by the DSM specialists within Idaho Power. The economic and other independent variables for the regression models are provided by third-party data providers and internally derived time-series for Idaho Power's service area.

Figure 16 illustrates the 2018 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (38 percent), followed by dairy (18 percent) and construction (7 percent). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, and health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

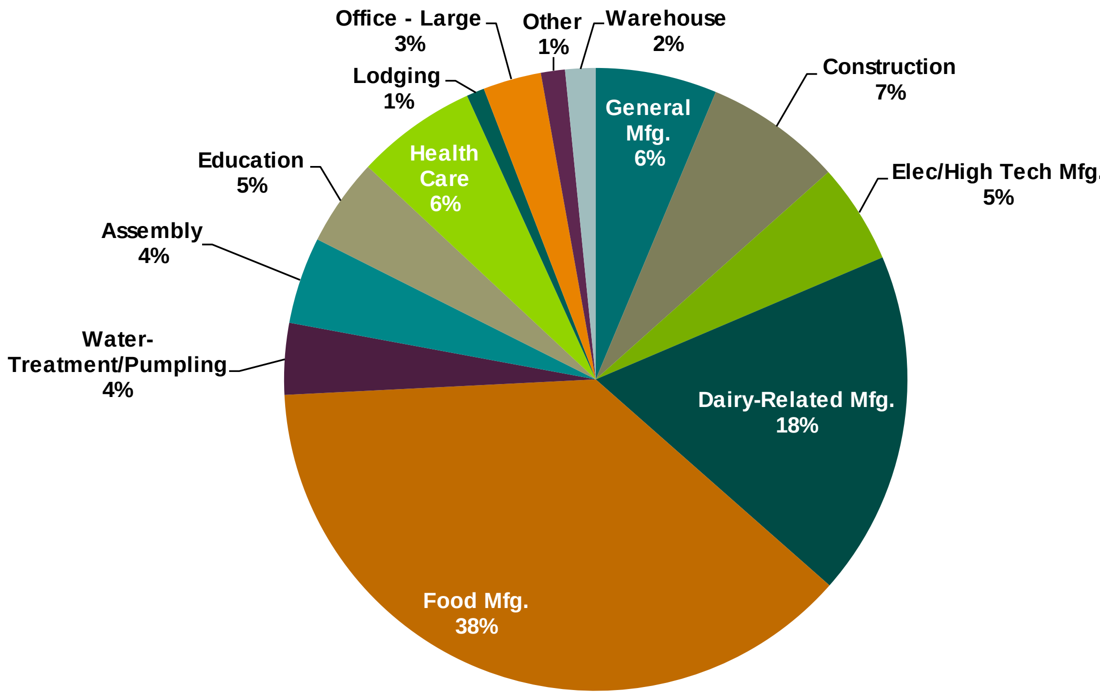

Figure 16. **Industrial electricity consumption by industry group (based on 2018 sales)**

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and variables such as, economics, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models applied to the appropriate forecasts of independent time series of energy use. From this output, the history and forecast of DSM is subtracted. Figure 17 shows the general forecasting methodology used for both the commercial and industrial sectors.

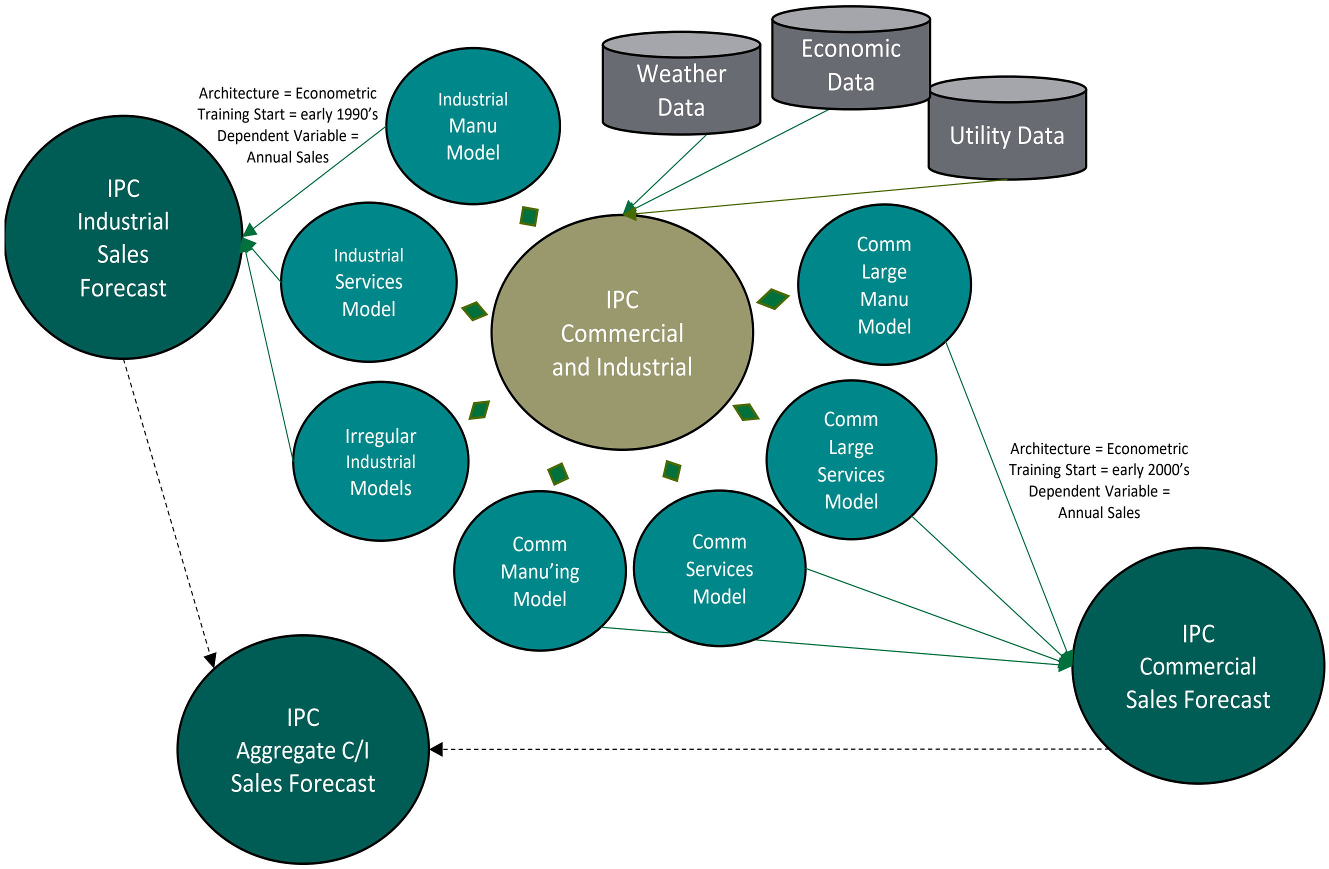

Figure 17. Commercial and industrial general sales forecast methodology

IRRIGATION

The irrigation category is comprised of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

The expected-case irrigation load is forecast to increase slowly from 222 aMW in 2019 to 258 aMW in 2038, an average annual compound growth rate of 0.8 percent. In the 70th-percentile scenario, irrigation load is projected to be 237 aMW in 2019 and 273 aMW in 2038. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast slower growth than the system in irrigation load from 2019 to 2038. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

Table 10. Irrigation load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	257	264	273	293	0.7%
70th Percentile	237	244	253	273	0.7%
Expected Case	222	230	238	258	0.8%

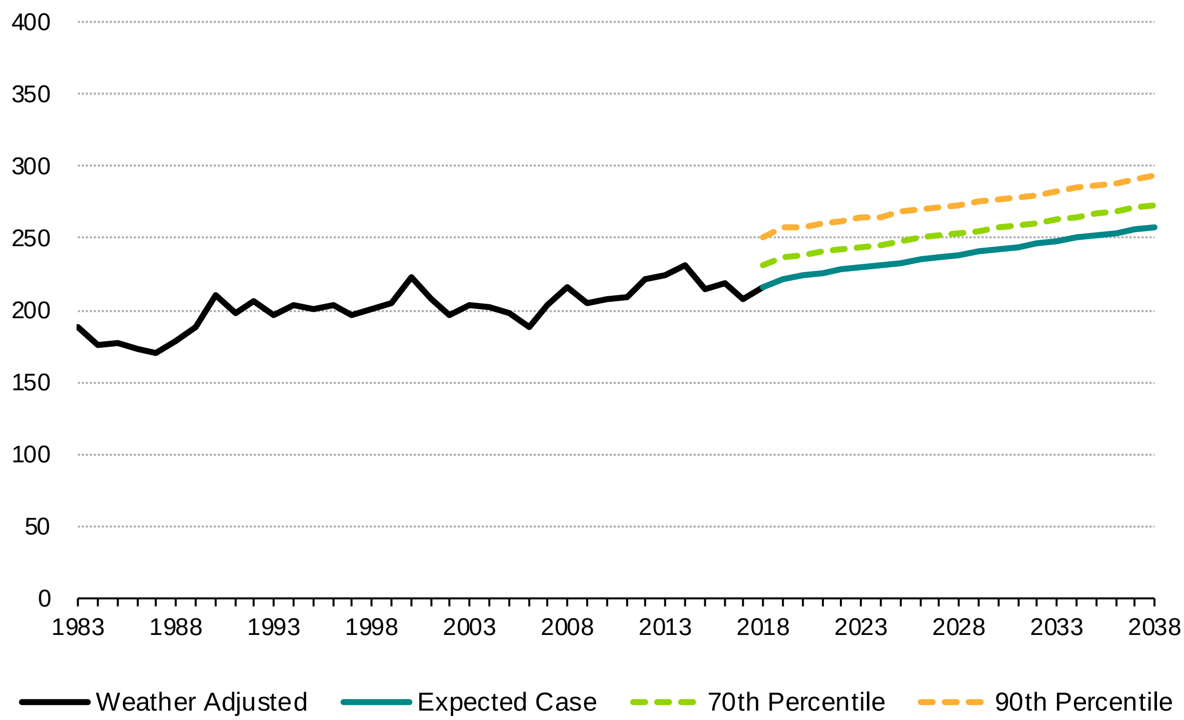

Figure 18. Forecast irrigation load (aMW)

The annual average loads in Table 10 and Figure 18 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can constitute nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy consumed during July for general business sales. The forecasted increase of sales is due to the increased customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs. Additionally, the trend toward more water intensive crops, primarily alfalfa and corn, due to growth in the dairy industry, explains most of the increased energy consumption in recent years.

The 2019 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; Palmer Z Index (calculated by the National Ocean and Atmospheric Administration [NOAA] from a combination of precipitation, temperature, and soil moisture data); Moody's Producer Price Index: Prices Received by Farmers, All Farm Products; and annual maximum irrigation customer counts.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt-hours (MWh) to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 2018, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2018, the number of active irrigation accounts had increased to 20,459 and is projected to be over 26,000 at the end of the planning period in 2038.

As with other sectors, average use per customer is an important consideration. Since 1988, Idaho Power has experienced growth in the number of irrigation customers but slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler irrigated land. The conversion rate is slow and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells. In future forecasts, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company 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 regulatory body. A special contract allows 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 with for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers comprise the forecast category labeled additional firm load.

In the expected-case forecast, additional firm load is expected to increase from 109 aMW in 2019 to 137 aMW in 2038, an average growth rate of 1.2 percent per year over the planning period (Table 11). The additional firm load energy and demand forecasts in the 70^{th}- and 90^{th}-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 19.

Table 11. Additional firm load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Expected Case	109	122	133	137	1.2%

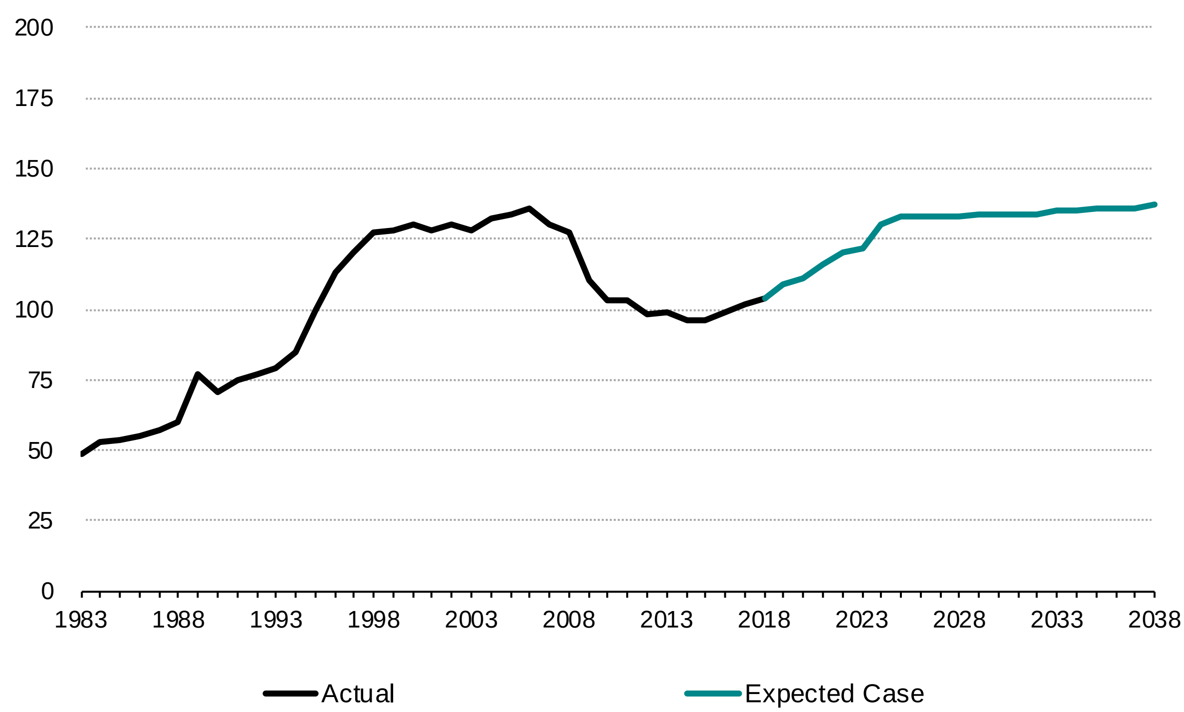

Figure 19. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,900-6,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, and corporate and general services. Micron Technology's electricity use is a function of the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States (US). The future electricity usage at the plant is expected to stay flat throughout the twenty-year planning period.

Idaho National Laboratory

INL is part of the US Department of Energy's (DOE) complex of national laboratories. INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2038 for the INL. The forecast calls for loads to slowly increase through 2023, step up in 2024, then levelize through the remainder of the forecast period.

ADDITIONAL CONSIDERATIONS

Several influential components and their associated impacts to the sales forecast are treated differently in the forecasting and planning process. The following discussion touches on several of those important topics.

Energy Efficiency

Energy efficiency (EE) influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on customers has increased in importance relative to utility programs, Idaho Power continues to modify its forecasting models to fully capture the impact. Idaho Power works closely with its internal Demand Side Management (DSM) program managers and utilizes the updated potential study, most recently developed by Applied Energy Group (AEG). DSM guidance and the achievable potential from AEG are used as a benchmark metric for validating forecast model output.

For residential models, the physical unit flow of energy-efficient products is captured through integrating regional energy efficient product-shipments data into the retail and wholesale distribution channels. The source for the shipments data is the Department of Energy (DOE) and is consistent with DOE's National Energy Model (NEM). This data is first refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes).

The DOE/Itron data is recognized in the industry as well-specified for the homogeneous residential sector, however, although DOE data is available for the commercial sector, Idaho Power's test-modeling of the data indicates that the regional data does not provide sufficient segmentation to recognize the heterogeneous differences between the Idaho regional micro-economic composition and the mountain region economy. As discussed in the previous section on forecast methodology within the commercial class, Idaho Power segments the commercial customers by economic and energy profiles and incorporates historical energy efficiency adoption into billed sales. Thus, the energy efficiency is directly modeled into the forecast model energy variable and the forecast is adjusted in conformance with the DSM and AEG potential study forecast to recognize energy efficiency. DOE data is not available for the industrial sector.

The weather and agricultural volatility of the billed sales for the irrigation sector is not well-suited for modeling energy efficiency impacts. Idaho Power monitors energy efficiency implementation in history and forecasts from internal and external sources (DSM staff and presently AEG). The trend of historical implementation (imbedded in the historical usage data) provides a guideline for evaluating the model forecast output relative to expected DSM and codes and standards.

As discussed above, Idaho Power continuously evaluates the models for adequately capturing the impacts of energy efficiency and implements improvements when indicated. With input from

DSM program managers and AEG's knowledge base, Idaho Power retains a high confidence in the representation of the impacts of energy efficiency in the forecast.

A more detailed description of DSM can be found in the main IRP document under the Energy Efficiency Section. Additionally, the company publishes a dedicated DSM annual report submitted to the regulatory agencies.

On-Site Generation

In recent years, the number of customers transitioning to net-metering service (Schedules 6, 8, and 84) has risen dramatically, especially for residential customers. While the current population of on-site generation customers is one-half of one percent of the population of retail customers, recent adoption of solar is relatively strong for our service area.

The installation of generating and storage equipment at customer sites will cause the demand for electricity delivered by Idaho Power to be reshaped throughout the year. It is important to measure the overall and future impact on the sales forecast. Therefore, this year's long-term sales forecast was adjusted downward to reflect the impact of the increase in the number customers with on-site generation, specifically solar, connecting to our system.

Schedules 6, 8, and 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact per customer (in kWh) was then multiplied by forecasts of the Schedule 6, 8, and 84 residential and commercial customer counts to estimate the future energy impact on the sales forecast. The forecast of net metering customers serves as a function of historical trends and current policy considerations.

The resulting forecast of net-metering customers multiplied by the estimated use-per-customer sales impact per customer results in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2038, the annual residential sales forecast reduction was about 38 aMW, and the commercial reduction was less than 4 aMW.

Electric Vehicles

The load forecast includes an update of the impact of electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While EV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, limiting attributes of vehicle range and refueling time continue to improve the competitiveness of these vehicles to non-electric models.

As the market grows, historical adoption data builds to provide a foundation for forecasting adoption rates and for the models to evolve. IPC receives detailed registration data from Idaho Transportation Department (ITD). The data provides county-level registration which provides a basis for determining IPC service-territory vehicle inventory. However, at present, this data is only available for battery-only vehicles and data for hybrid engine-battery vehicles was not available for this forecast update. Other data sources for monitoring the outlook for PEV adoption includes the U.S. Department of Energy, R.L. Polk, and Moody's Analytics.

Recent registration data shows a strong correlation between vehicles transferred into the service territory and growth of residential in-migration from states with higher PEV share (e.g., California and Washington). IPC subsequently developed a regression model to test the relationship utilizing migration, population and Moody's car registration forecasts. The model results confirm the correlation and the forecast outlook conforms well with the generalized model utilizing DOE data.

The evolution of the PEV market shows that high adoption continues to be evident in warmer climates, high-density and affluent population centers. The IPC forecast for PEVs shows that the service territory will continue to fall into the lower adoption ranges. IPC continues to monitor battery technology advancement, vehicle prices, charging rates and charging station availability which will serve to build the adoption rate in the service territory.

Demand Response

Beginning with the 2009 IRP, the reduction in load associated with demand response programs has been effectively treated as a supply side resource and accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed *in Appendix C—Technical Appendix*.

As supply-side resources, demand response program impacts are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak hour load reduction is integrated into the sales and load forecast models. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2018 Annual Report*.

Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long term trends in electricity sales. Changes in relative fuel prices can also impact the future demand for electricity. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 12. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

Table 12. Residential fuel-price escalation (2019–2038) (average annual percent change)

	Nominal	Real*
Electricity—2019 IRP	1.3%	-0.6%
Electricity—2017 IRP	1.6%	–0.3%
Natural Gas	2.9%	1.0%

* Adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1980 to 2018 and over the forecast period 2019 to 2038. Both nominal and real prices are shown. In the 2019 IRP, nominal electricity prices are expected to climb to about 13 cents per kWh by the end of the forecast period in 2038. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 0.6 percent annually. In the 2017 IRP, nominal electricity prices were assumed to climb to about 13 cents per kWh by 2038, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of -0.3 percent annually.

The electricity price forecast used to prepare the sales and load forecast in the 2019 IRP reflected 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 yielded 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.

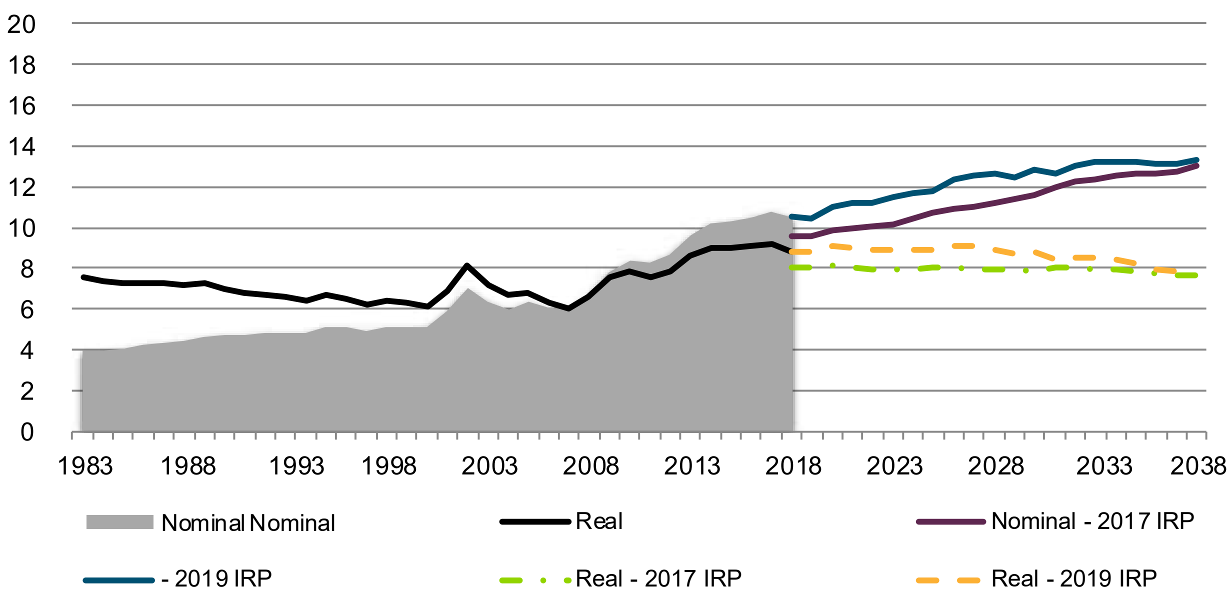

Figure 20. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, nominal electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually. More recently, over the period 2008 to 2018, nominal electricity prices rose 78 percent overall, an annual average compound growth rate of 4.5 percent annually.

Figure 21 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1983 to 2017 and forecast prices from 2018 to 2038. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have declined about 39 percent, compared to 2017. Nominal natural gas prices are initially expected to drop by 7 percent in 2018, then rise at a steady pace throughout the remainder of the forecast period, increasing 80 percent by 2038, growing at an average rate of 2.9 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.0 percent annually.

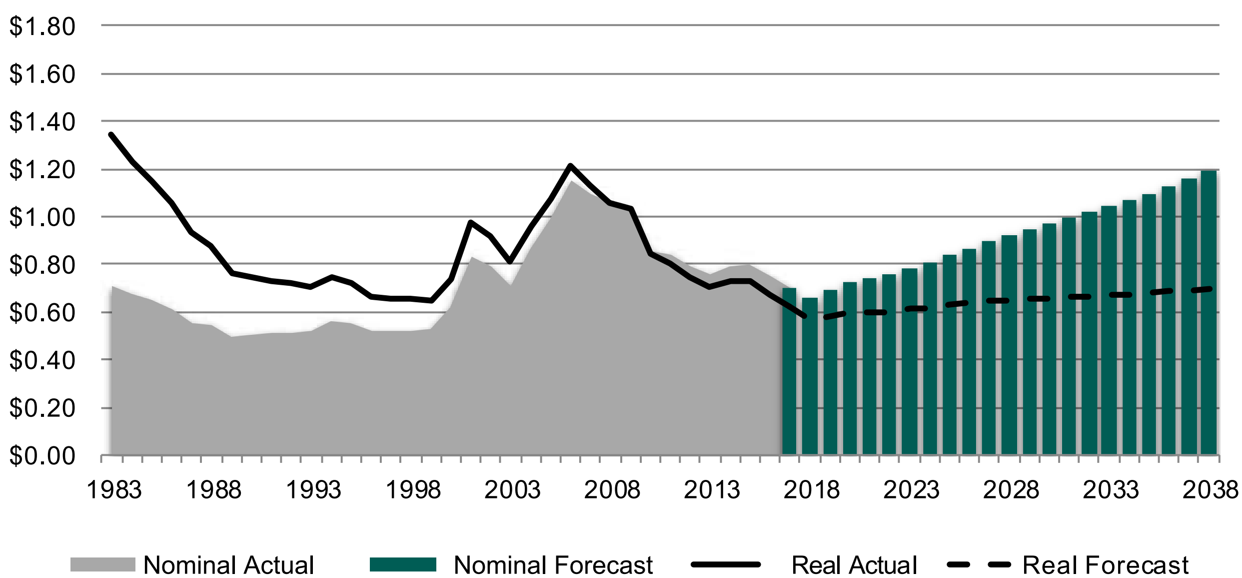

Figure 21. Forecast residential natural gas prices (dollars per therm)

One consideration in determining the operating costs of space heating and water heating is fuel cost, if future natural gas price increases outpace electricity price increases, heating with electricity would become more advantageous when compared to that of natural gas. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. In the 2019 IRP price forecast, the long-term direction in real electricity prices (adjusted for inflation) is downward and the long-term projection in real natural gas prices is upward, with prices slowly rising throughout the forecast period.

Other Considerations

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be converted from billed periods to calendar months to synchronize them with the time period in which load is generated. The calendar-month sales are then converted to calendar-month average load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2019 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

Hourly Load Forecast

As a result of stakeholder feedback and comments filed in the 2017 IRP Idaho Power has leveraged several years of advanced metering infrastructure (AMI) data to adopte a new hourly load forecasting methodology to be used in the 2019 IRP. The use of AMI data expanded its footprints at Idaho Power and is utilized to inform an hourly load forecast that conforms with forecast methods mentioned throughout this document.

Historical IRP Methodology

Historically, Idaho Power has utilized metered system generation reads and weather data to build a typical system load factor or hourly system shape based on a previous year, which was then applied to the monthly load forecast for the IRP planning horizon. This methodology produced a consistent system shape throughout the load forecast, but it lacked the significant statistical footing of using individual hourly regressions rooted in AMI.

2019 IRP Methodology

In the time between IRP filings, Idaho Power began exploring potential methodology changes regarding hourly load forecasting relative to what the Company currently had in place. While evaluating potential changes, the Company believes it is prudent to maintain the integrity of the historic long-term forecasting methodologies previously employed by Load Forecasting.

Based on the research, the Company concluded that the new methodology should be formed using a neural network. A neural network utilizes the stability of monthly sales data to calibrate and ground the hourly data via monthly peak regressions. Further, the methodology employs control and flexibility on the neural network while still leaning on its more robust statistical underpinnings.

Enhancements to Hourly Load Forecasting

To begin the process, the Company engaged in consultation with the Itron. Together, Idaho Power and Itron designed the framework to introduce concepts of a neural network model that utilized two non-linear nodes and was hinged on currently accepted load forecasting processes. The result of this methodology brought statistical confidence of hourly load modeling to the Company while still conforming to the stability of the legacy methodology of monthly sales forecasting.

An industry approach to weather responsiveness would be to utilize a linear model based on a heating degree day or cooling degree day level of 65 degrees Fahrenheit (°F) (actual point may differ by local utility weather characteristics). Utilities will also often use splines in regression equations to define the weather function to reflect the change of slope as the average daily temperature moves away from the 65°F mark and there is less weather responsiveness. This methodology works very well by minimizing the potential impact of overfitting. Building on this framework, Idaho Power uses a non-linear approach, wherein the derivative or local slope of a curve is calculated at each instance along the weather responsiveness curve. This responsiveness is captured in the neural network.

The neural network design adopted by Idaho Power outputs a single series of hourly energy with only one hidden layer that contains two nodes (H1 and H2) representing the heating and cooling effects along the sales curve. Each of the H1 and H2 nodes uses a logistic activation function with a linear function applied to the output layer, where impacts of the calendar (weekend, weekday, holidays, etc.) are captured.

A distinct model is developed for each hour of the year to capture the full spectrum of temperature responsiveness. For each non-linear hourly model, an instantaneous derivative value is calculated along the curve to obtain the relationship of energy sales to temperature. A key initiative for Idaho Power when using a neural network framework is controllability of calculations and reducing risk of overfitting of the tails of the distribution. This is achieved by capturing the derivative value and using it in the hourly forecast using 5-degree gradation bins. Further, by releasing the slopes in this fashion, it creates unique weighting schemes by hour and facilitates the construction of lagged weather impact, weekends, and holidays. The result of these hourly models is a transparent set of weather response functions.

At this point, a typical meteorological year is developed using a rolling 30 years of weather history within the Idaho Power service territory. The Company then uses an algorithm to rank and average the daily temperature within a month from hottest to coldest, averaging the daily temperature for each rank across years. The result is an appropriate representation of severe, moderate, and mild daily temperatures for each month. The Company then uses that ranked and averaged typical weather by month and employs a transformation algorithm to reorder days based on a typical weather pattern. Finally, a rotation algorithm is used to ensure that the values over the forecast periods occur on the same day of the week throughout the forecast period, removing the year-to-year variation in the hourly load shape based on where it lands on the calendar of the given forecast year.

Hourly System Load Forecast Design

The output from the neural network is then joined with the abovementioned typical meteorological year (TMY) to develop a near final hourly forecast. An important aspect of the design was for the Company to preserve the monthly sales and monthly peak forecast that has been used historically. The newly developed methodology leverages a more statistically confident approach for allocated sales by hour within the month. To maintain conformance with the historical methodology, the Company applies a calibration algorithm to the hourly forecast to both the monthly peak and energy sales within a month as produced by the legacy linear forms the Company operates. The output of hourly sales and subsequent monthly peaks, as defined from the above-mentioned models, are adjusted such that the duration curve receives minimal adjustment during or around the peak hour, and any required adjustment grows larger as it moves out along the duration curve. This minimizes potential impacts of creating large hour-to-hour swings.

CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

Appendix A1. Historical and Projected Sales and Load

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1978–2018 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	7,275		901
1979	7,612	4.6%	956
1980	7,880	3.5%	976
1981	8,183	3.9%	1,015
1982	7,865	-3.9%	979
1983	8,038	2.2%	999
1984	8,126	1.1%	1,007
1985	8,279	1.9%	1,028
1986	8,345	0.8%	1,036
1987	8,492	1.8%	1,055
1988	8,822	3.9%	1,093
1989	9,217	4.5%	1,145
1990	9,589	4.0%	1,191
1991	9,753	1.7%	1,210
1992	10,000	2.5%	1,239
1993	10,248	2.5%	1,273
1994	10,670	4.1%	1,325
1995	11,085	3.9%	1,374
1996	11,446	3.3%	1,417
1997	11,769	2.8%	1,460
1998	12,241	4.0%	1,517
1999	12,517	2.3%	1,551
2000	12,942	3.4%	1,603
2001	13,071	1.0%	1,616
2002	12,768	-2.3%	1,584
2003	13,096	2.6%	1,623
2004	13,354	2.0%	1,654
2005	13,652	2.2%	1,696
2006	13,955	2.2%	1,730
2007	14,373	3.0%	1,783
2008	14,467	0.7%	1,786
2009	13,992	-3.3%	1,736
2010	13,841	-1.1%	1,716
2011	13,864	0.2%	1,719
2012	14,061	1.4%	1,738
2013	14,096	0.2%	1,755
2014	14,262	1.2%	1,765
2015	14,102	-1.1%	1,750
2016	14,267	1.2%	1,772
2017	14,380	0.8%	1,778
2018	14,570	1.3%	1,806

Company System Load

Projected Company System Sales and Load, 2019–2038

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	14,788	1.5%	1,833
2020	14,963	1.2%	1,849
2021	15,139	1.2%	1,876
2022	15,329	1.3%	1,899
2023	15,517	1.2%	1,923
2024	15,752	1.5%	1,946
2025	15,923	1.1%	1,972
2026	16,066	0.9%	1,990
2027	16,205	0.9%	2,008
2028	16,362	1.0%	2,022
2029	16,530	1.0%	2,048
2030	16,675	0.9%	2,066
2031	16,820	0.9%	2,084
2032	16,961	0.8%	2,096
2033	17,082	0.7%	2,117
2034	17,224	0.8%	2,134
2035	17,381	0.9%	2,154
2036	17,544	0.9%	2,168
2037	17,702	0.9%	2,194
2038	17,850	0.8%	2,212

Residential Load

Historical Residential Sales and Load, 1978–2018 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	194,650		14,714	2,864		322
1979	202,982	4.3%	13,892	2,820	-1.5%	330
1980	209,629	3.3%	14,846	3,112	10.4%	355
1981	213,579	1.9%	14,805	3,162	1.6%	357
1982	216,696	1.5%	13,653	2,959	-6.4%	339
1983	219,849	1.5%	14,338	3,152	6.5%	359
1984	222,695	1.3%	14,085	3,137	-0.5%	357
1985	225,185	1.1%	13,968	3,145	0.3%	359
1986	227,081	0.8%	14,091	3,200	1.7%	366
1987	228,868	0.8%	14,012	3,207	0.2%	367
1988	230,771	0.8%	14,269	3,293	2.7%	375
1989	233,370	1.1%	14,272	3,331	1.1%	381
1990	238,117	2.0%	14,303	3,406	2.3%	389
1991	243,207	2.1%	14,409	3,504	2.9%	401
1992	249,767	2.7%	14,157	3,536	0.9%	403
1993	258,271	3.4%	14,134	3,651	3.2%	418
1994	267,854	3.7%	14,048	3,763	3.1%	430
1995	277,131	3.5%	14,017	3,885	3.2%	444
1996	286,227	3.3%	13,791	3,947	1.6%	451
1997	294,674	3.0%	13,717	4,042	2.4%	461
1998	303,300	2.9%	13,770	4,176	3.3%	477
1999	312,901	3.2%	13,619	4,261	2.0%	487
2000	322,402	3.0%	13,436	4,332	1.6%	494
2001	331,009	2.7%	13,189	4,366	0.8%	497
2002	339,764	2.6%	12,701	4,315	-1.2%	494
2003	349,219	2.8%	12,779	4,463	3.4%	509
2004	360,462	3.2%	12,744	4,594	2.9%	525
2005	373,602	3.6%	12,729	4,756	3.5%	545
2006	387,707	3.8%	12,967	5,027	5.7%	575
2007	397,286	2.5%	13,002	5,165	2.7%	590
2008	402,520	1.3%	12,890	5,188	0.4%	591
2009	405,144	0.7%	12,758	5,169	-0.4%	589
2010	407,551	0.6%	12,473	5,083	-1.7%	580
2011	409,786	0.5%	12,434	5,095	0.2%	581
2012	413,610	0.9%	12,351	5,109	0.3%	581
2013	418,892	1.3%	12,043	5,045	-1.2%	579
2014	425,036	1.5%	11,939	5,074	0.6%	576
2015	432,275	1.7%	11,643	5,033	-0.8%	575
2016	440,362	1.9%	11,585	5,102	1.4%	582
2017	448,800	1.9%	11,496	5,159	1.1%	588
2018	459,128	2.3%	11,335	5,204	0.9%	594

Projected Residential Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	470,304	2.4%	11,190	5,263	1.1%	601
2020	481,116	2.3%	11,047	5,315	1.0%	606
2021	491,696	2.2%	10,913	5,366	1.0%	613
2022	502,081	2.1%	10,800	5,422	1.1%	620
2023	512,271	2.0%	10,734	5,499	1.4%	628
2024	522,267	2.0%	10,665	5,570	1.3%	635
2025	532,070	1.9%	10,595	5,637	1.2%	644
2026	541,681	1.8%	10,506	5,691	0.9%	650
2027	551,098	1.7%	10,417	5,741	0.9%	656
2028	560,321	1.7%	10,366	5,808	1.2%	662
2029	569,351	1.6%	10,339	5,886	1.3%	672
2030	578,200	1.6%	10,274	5,940	0.9%	679
2031	586,943	1.5%	10,218	5,998	1.0%	685
2032	595,553	1.5%	10,161	6,052	0.9%	689
2033	604,028	1.4%	10,084	6,091	0.6%	696
2034	612,354	1.4%	10,051	6,155	1.0%	703
2035	620,539	1.3%	10,051	6,237	1.3%	713
2036	628,700	1.3%	10,064	6,327	1.4%	721
2037	636,852	1.3%	10,074	6,415	1.4%	733
2038	645,069	1.3%	10,073	6,498	1.3%	742

Commercial Load

Historical Commercial Sales and Load, 1978–2018 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	27,831		52,510	1,461		169
1979	28,087	0.9%	56,373	1,583	8.3%	180
1980	28,797	2.5%	54,169	1,560	-1.5%	178
1981	29,567	2.7%	54,311	1,606	2.9%	184
1982	30,167	2.0%	54,130	1,633	1.7%	186
1983	30,776	2.0%	52,660	1,621	-0.8%	185
1984	31,554	2.5%	53,626	1,692	4.4%	193
1985	32,418	2.7%	54,254	1,759	3.9%	202
1986	33,208	2.4%	53,980	1,793	1.9%	204
1987	33,975	2.3%	53,546	1,819	1.5%	208
1988	34,723	2.2%	54,467	1,891	4.0%	216
1989	35,638	2.6%	55,468	1,977	4.5%	226
1990	36,785	3.2%	55,909	2,057	4.0%	236
1991	37,922	3.1%	56,341	2,137	3.9%	244
1992	39,022	2.9%	56,578	2,208	3.3%	252
1993	40,047	2.6%	58,289	2,334	5.7%	267
1994	41,629	4.0%	58,445	2,433	4.2%	279
1995	43,165	3.7%	58,787	2,538	4.3%	291
1996	44,995	4.2%	62,134	2,796	10.2%	319
1997	46,819	4.1%	62,230	2,914	4.2%	333
1998	48,404	3.4%	62,894	3,044	4.5%	349
1999	49,430	2.1%	64,283	3,178	4.4%	363
2000	50,117	1.4%	66,151	3,315	4.3%	379
2001	51,501	2.8%	67,575	3,480	5.0%	397
2002	52,915	2.7%	64,864	3,432	-1.4%	392
2003	54,194	2.4%	64,405	3,490	1.7%	399
2004	55,577	2.6%	64,075	3,561	2.0%	406
2005	57,145	2.8%	63,637	3,637	2.1%	416
2006	59,050	3.3%	63,613	3,756	3.3%	429
2007	61,640	4.4%	63,471	3,912	4.2%	447
2008	63,492	3.0%	62,334	3,958	1.2%	449
2009	64,151	1.0%	59,821	3,838	-3.0%	439
2010	64,421	0.4%	58,973	3,799	-1.0%	433
2011	64,921	0.8%	58,596	3,804	0.1%	434
2012	65,599	1.0%	59,059	3,874	1.8%	441
2013	66,357	1.2%	58,753	3,899	0.6%	447
2014	67,113	1.1%	59,067	3,964	1.7%	451
2015	68,000	1.3%	58,639	3,987	0.6%	456
2016	68,883	1.3%	58,178	4,007	0.5%	460
2017	69,850	1.4%	58,014	4,052	1.1%	461
2018	71,104	1.8%	57,884	4,116	1.6%	471

Projected Commercial Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	72,507	2.0%	57,135	4,143	0.7%	473
2020	74,033	2.1%	56,680	4,196	1.3%	478
2021	75,561	2.1%	56,057	4,236	0.9%	484
2022	77,060	2.0%	55,719	4,294	1.4%	491
2023	78,519	1.9%	55,311	4,343	1.1%	496
2024	79,937	1.8%	54,911	4,389	1.1%	500
2025	81,315	1.7%	54,662	4,445	1.3%	508
2026	82,653	1.6%	54,451	4,501	1.3%	514
2027	83,985	1.6%	54,211	4,553	1.2%	520
2028	85,328	1.6%	54,030	4,610	1.3%	525
2029	86,686	1.6%	53,877	4,670	1.3%	534
2030	88,060	1.6%	53,754	4,734	1.4%	541
2031	89,447	1.6%	53,552	4,790	1.2%	547
2032	90,846	1.6%	53,401	4,851	1.3%	553
2033	92,256	1.6%	53,152	4,904	1.1%	560
2034	93,674	1.5%	52,885	4,954	1.0%	566
2035	95,097	1.5%	52,615	5,004	1.0%	572
2036	96,522	1.5%	52,331	5,051	0.9%	575
2037	97,946	1.5%	52,047	5,098	0.9%	582
2038	99,367	1.5%	51,706	5,138	0.8%	587

Irrigation Load

Historical Irrigation Sales and Load, 1978–2018 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	10,476		154,696	1,621		185
1979	10,711	2.2%	163,250	1,749	7.9%	199
1980	10,854	1.3%	160,522	1,742	-0.4%	198
1981	11,248	3.6%	168,088	1,891	8.5%	216
1982	11,312	0.6%	154,149	1,744	-7.8%	199
1983	11,133	-1.6%	147,935	1,647	-5.5%	188
1984	11,375	2.2%	136,138	1,549	-6.0%	176
1985	11,576	1.8%	133,571	1,546	-0.2%	177
1986	11,308	-2.3%	133,880	1,514	-2.1%	173
1987	11,254	-0.5%	132,363	1,490	-1.6%	170
1988	11,378	1.1%	137,228	1,561	4.8%	178
1989	11,957	5.1%	137,547	1,645	5.3%	188
1990	12,340	3.2%	149,104	1,840	11.9%	210
1991	12,484	1.2%	138,808	1,733	-5.8%	198
1992	12,809	2.6%	140,990	1,806	4.2%	206
1993	13,078	2.1%	131,515	1,720	-4.8%	196
1994	13,559	3.7%	131,687	1,786	3.8%	204
1995	13,679	0.9%	128,970	1,764	-1.2%	201
1996	14,074	2.9%	126,538	1,781	0.9%	203
1997	14,383	2.2%	119,833	1,724	-3.2%	197
1998	14,695	2.2%	119,957	1,763	2.3%	201
1999	14,912	1.5%	120,501	1,797	1.9%	205
2000	15,253	2.3%	128,579	1,961	9.1%	223
2001	15,522	1.8%	117,148	1,818	-7.3%	208
2002	15,840	2.0%	108,904	1,725	-5.1%	197
2003	16,020	1.1%	111,637	1,788	3.7%	204
2004	16,297	1.7%	108,844	1,774	-0.8%	202
2005	16,936	3.9%	102,342	1,733	-2.3%	198
2006	17,062	0.7%	97,182	1,658	-4.3%	189
2007	17,001	-0.4%	105,177	1,788	7.8%	204
2008	17,428	2.5%	108,923	1,898	6.2%	216
2009	17,708	1.6%	101,440	1,796	-5.4%	205
2010	17,846	0.8%	102,016	1,821	1.4%	208
2011	18,292	2.5%	99,972	1,829	0.4%	209
2012	18,675	2.1%	104,167	1,945	6.4%	221
2013	19,017	1.8%	103,711	1,972	1.4%	225
2014	19,328	1.6%	104,486	2,020	2.4%	231
2015	19,756	2.2%	95,158	1,880	-6.9%	215
2016	20,042	1.4%	96,149	1,927	2.5%	219
2017	20,246	1.0%	89,806	1,818	-5.6%	208
2018	20,459	1.1%	92,543	1,893	4.1%	216

Projected Irrigation Sales and Load, 2019–2038

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	20,727	1.3%	93,816	1,945	2.7%	222
2020	21,010	1.4%	93,458	1,964	1.0%	224
2021	21,290	1.3%	92,870	1,977	0.7%	226
2022	21,570	1.3%	92,453	1,994	0.9%	228
2023	21,852	1.3%	92,026	2,011	0.8%	230
2024	22,134	1.3%	91,565	2,027	0.8%	231
2025	22,413	1.3%	91,103	2,042	0.7%	233
2026	22,694	1.3%	90,684	2,058	0.8%	235
2027	22,975	1.2%	90,304	2,075	0.8%	237
2028	23,253	1.2%	89,943	2,091	0.8%	238
2029	23,537	1.2%	89,558	2,108	0.8%	241
2030	23,817	1.2%	89,198	2,124	0.8%	243
2031	24,096	1.2%	88,845	2,141	0.8%	244
2032	24,380	1.2%	88,474	2,157	0.8%	246
2033	24,658	1.1%	88,141	2,173	0.8%	248
2034	24,941	1.1%	87,815	2,190	0.8%	250
2035	25,219	1.1%	87,514	2,207	0.8%	252
2036	25,502	1.1%	87,223	2,224	0.8%	253
2037	25,781	1.1%	86,961	2,242	0.8%	256
2038	26,064	1.1%	86,694	2,260	0.8%	258

Industrial Load

Historical Industrial Sales and Load, 1978–2018 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	99		9,786,753	972		111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,412,391	2,308	-2.4%	261
2009	124	4.0%	17,987,570	2,224	-3.6%	254
2010	121	-2.0%	18,404,875	2,232	0.3%	254
2011	120	-1.1%	18,597,050	2,230	-0.1%	254
2012	115	-4.2%	19,757,921	2,271	1.8%	258
2013	114	-0.7%	20,281,837	2,314	1.9%	265
2014	113	-0.7%	20,863,653	2,363	2.1%	271
2015	116	2.8%	20,271,082	2,360	-0.1%	269
2016	118	1.4%	19,993,955	2,361	0.0%	270
2017	117	-1.1%	20,996,425	2,453	3.9%	280
2018	115	-1.6%	21,272,694	2,446	-0.3%	279

Projected Industrial Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	113	-1.7%	21,962,765	2,482	1.4%	284
2020	113	0.0%	22,221,031	2,511	1.2%	286
2021	115	1.8%	22,152,471	2,548	1.5%	291
2022	115	0.0%	22,350,111	2,570	0.9%	294
2023	115	0.0%	22,567,691	2,595	1.0%	296
2024	116	0.9%	22,582,643	2,620	0.9%	298
2025	116	0.0%	22,745,374	2,638	0.7%	301
2026	118	1.7%	22,479,895	2,653	0.5%	303
2027	118	0.0%	22,620,402	2,669	0.6%	305
2028	118	0.0%	22,722,807	2,681	0.5%	305
2029	118	0.0%	22,815,226	2,692	0.4%	307
2030	119	0.8%	22,697,036	2,701	0.3%	308
2031	121	1.7%	22,425,128	2,713	0.5%	310
2032	121	0.0%	22,487,311	2,721	0.3%	310
2033	121	0.0%	22,574,212	2,731	0.4%	312
2034	121	0.0%	22,636,506	2,739	0.3%	313
2035	123	1.7%	22,319,757	2,745	0.2%	313
2036	123	0.0%	22,360,334	2,750	0.2%	313
2037	124	0.8%	22,210,418	2,754	0.1%	314
2038	124	0.0%	22,243,637	2,758	0.1%	315

Additional Firm Sales and Load
Historical Additional Firm Sales and Load, 1978–2018

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	357		41
1979	373	4.4%	43
1980	360	-3.5%	41
1981	376	4.6%	43
1982	368	-2.4%	42
1983	425	15.6%	49
1984	466	9.7%	53
1985	471	1.1%	54
1986	482	2.3%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	-6.9%	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,122	0.8%	128
2000	1,143	1.9%	130
2001	1,118	-2.1%	128
2002	1,139	1.9%	130
2003	1,120	-1.7%	128
2004	1,156	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.0%	103
2011	906	0.0%	103
2012	862	-4.8%	98
2013	867	0.5%	99
2014	841	-2.9%	96
2015	842	0.1%	96
2016	870	3.3%	99
2017	897	3.1%	102
2018	910	1.4%	104

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Projected Additional Firm Sales and Load, 2019–2038

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	957	5.1%	109
2020	977	2.1%	111
2021	1,013	3.7%	116
2022	1,048	3.5%	120
2023	1,069	2.0%	122
2024	1,146	7.2%	130
2025	1,161	1.3%	133
2026	1,164	0.3%	133
2027	1,167	0.3%	133
2028	1,171	0.3%	133
2029	1,173	0.2%	134
2030	1,176	0.3%	134
2031	1,178	0.2%	134
2032	1,180	0.2%	134
2033	1,183	0.3%	135
2034	1,186	0.3%	135
2035	1,188	0.2%	136
2036	1,191	0.3%	136
2037	1,193	0.2%	136
2038	1,196	0.3%	137

*Includes Micron Technology, Simplot Fertilizer, and the INL

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INTEGRATED RESOURCE PLAN

2019

MARCH 15 • 2019

APPENDIX B: DSM ANNUAL REPORT

SAFE HARBOR STATEMENT

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EXECUTIVE SUMMARY

Idaho Power, through its energy efficiency programs, its customer education programs, and its focus on the customer experience, fully supports energy efficiency and demand response and encourages its customers to use energy wisely.

In 2018, Idaho Power's focus was not only on the pursuit of all cost-effective energy efficiency, but also improving the customer experience. One of the highlights was added functionality to My Account, an online energy portal where a customer can register to receive notifications for high or overdue bills via text message or email. Another project was sending a Welcome Kit to customers new to Idaho Power's service. Each Welcome Kit contains four LED lightbulbs, a night light, a "welcome to the neighborhood" greeting card, and an Energy Savings Made Easy "flip book" containing tips and residential program information. Over 30,000 customers were reached with this innovative effort, starting new customers on the path to saving energy.

Another highlight of 2018 was Idaho Power being recognized with the Governor's Award for Excellence in Energy Efficiency. This award honors a single facility or organization that demonstrates a commitment to energy efficiency at all levels through programming, implementation, and promotion. Idaho Gov. C.L. "Butch" Otter presented the award to Idaho Power President and CEO Darrel Anderson during the fall meeting of the Energy Efficiency Advisory Group (EEAG).

Figure 1. Idaho Power Senior Vice President and Chief Operating Officer Lisa Grow, Idaho Governor C.L. "Butch" Otter, Idaho Power President and CEO Darrel Anderson, Idaho Power Vice President of Customer Operations and Business Development Adam Richins, and Idaho Power Customer Relations and Energy Efficiency Senior Manager Theresa Drake

Figure 2. Idaho Power's Facebook post announcing the Governor's Award

Idaho Power's portfolio of energy efficiency program energy savings remains strong, with savings of 183,378 megawatt hours (MWh) in 2018, including the estimated savings from the Northwest Energy Efficiency Alliance (NEEA). These savings represent enough energy to power over 16,000 average homes for one year in Idaho Power's service area. In 2018, the company's energy efficiency portfolio was cost-effective from both the total resource cost (TRC) test and the utility cost test (UCT) perspectives with ratios of 2.26 and 3.04, respectively. The portfolio was also cost-effective from the participant cost test (PCT) ratio, which was 2.85. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, was 158,412 MWh in 2018.

Idaho Power successfully operated all three of its demand response programs in 2018. The total demand response capacity from the company's programs was 382 megawatts (MW). Energy efficiency and demand response are important aspects of Idaho Power's resource planning process. Idaho Power's 2018 achievements in energy savings exceeded the annual savings target identified in Idaho Power's 2017 Integrated Resource Plan (IRP). On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002.

Total expenditures from all funding sources of demand-side management (DSM) activities was $44 million in 2018. DSM program funding comes from the Idaho and Oregon Riders, Idaho Power base rates, and the annual power cost adjustment (PCA). The company's demand response incentives are recovered through base rates and the annual PCA in Idaho, while Oregon demand response incentives are funded through the Oregon Rider.

In 2018, Idaho Power continued to expand the reach and frequency of its residential energy efficiency campaign with digital and print marketing, including an increase in social media activity. The company also continued promoting the three Commercial and Industrial (C&I) Energy Efficiency Program options as a single program.

Idaho Power uses stakeholder input to enhance its programs. The company met regularly with EEAG and individual customers seeking input on program improvement. To find growth in the program portfolio, the company relied on its Program Planning Group (PPG) that was initiated in 2014, NEEA's Regional Emerging Technology Advisory Committee (RETAC), and E Source resources. Additionally, Idaho Power continued to refine its program processes through evaluations, customer surveys, and research to make it easier for its customers to participate.

In 2018, Idaho Power continued to distribute Energy-Saving Kits (ESK) at no cost to customers on request. By the end of the year, 44,691 ESKs were shipped to customer homes: 18,383 kits to homes with electric water heaters and 26,308 to homes with alternate-source water heaters. In 2018, Idaho Power developed an ESK for commercial customers, distributing over 1,600 kits to small commercial customers in Idaho and Oregon.

This *Demand Side Management 2018 Annual Report* provides a review of the company's DSM activities and finances throughout 2018 and outlines Idaho Power's plans for future DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419. Idaho Power will provide a copy of the report to the Public Utility Commission of Oregon (OPUC) under Oregon Docket Utility Miscellaneous (UM) No. 1710.

INTRODUCTION

Idaho Power, through its energy efficiency programs, its customer education programs, and its focus on the customer experience, fully supports energy efficiency and demand response and encourages its customers to use energy wisely.

Energy efficiency and demand response provide economic and operational benefits to the company and its customers; in 2018, Idaho Power continued to pursue all cost-effective energy efficiency across its service area. Idaho Power focuses on the customer experience when providing information and programs that ensure customers have opportunities to learn about their energy use, how to use energy wisely, and participate in programs.

This report focuses on Idaho Power's demand-side management (DSM) activities and results for 2018 and previews planned activities for 2019. The appendices provide detailed information on the company's DSM activities and detailed financial information from for 2018. *Supplement 1: Cost-Effectiveness* provides detailed cost-effectiveness data and *Supplement 2: Evaluation* provides copies of Idaho Power's evaluations, reports, and research conducted in 2018. *Supplement 2: Evaluation* includes the *Historical DSM Expense and Performance* report (formerly Appendix 4) which details DSM activities and financial information from 2002 to 2018.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and to provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. Idaho Power considers cost-effective energy efficiency the company's least-cost resource and pays particular attention to ensuring the best value to Idaho Power's customers. Idaho Power strives to provide customers with programs and information to help them manage their energy use wisely.

The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. For economic and administrative efficiency and to reduce customer confusion, Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas. Idaho Power has been locally operated since 1916 and serves more than 550,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon.

Figure 3. Idaho Power service area map

Idaho Power's energy efficiency programs are available to all customer sectors in Idaho Power's service area and focus on reducing energy use by identifying homes, buildings, equipment, or components for which an energy-efficient design, replacement, or repair can achieve energy savings. Some energy efficiency programs include behavioral components. For example, the Residential Energy Efficiency Education Initiative (REEEI), the Smart-Saver Pledge, the School Cohort, and the Home Energy Report pilot program, which began in 2017, all have behavioral components associated with them.

Savings from energy efficiency programs are measured in terms of energy savings on a kilowatt-hour (kWh) or megawatt-hour (MWh) basis. These programs usually supply energy savings throughout the year at different times depending on the energy efficiency measure put in place. Idaho Power shapes these savings based on the end use to estimate energy reduction at specific times of the day and year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings); residential and commercial retrofit applications; and irrigation and industrial system improvement or replacement. Idaho Power's custom incentives offer a wide range of opportunities to its irrigation, industrial, large-commercial, governmental, and school customers to execute energy-saving projects.

Energy efficiency and demand response funding comes from Idaho Power base rates, the Idaho and Oregon Riders (Rider), and the annual power cost adjustment (PCA) in Idaho. Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider. Total expenditures from all funding sources on DSM-related activities was $ $44 million in 2018 (Figure 5).

Idaho Power started its modern demand response programs in 2002, and now has over 11 percent of its all-time peak load available due to demand response programs. The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side peaking resources. The company estimates future capacity needs through the IRP planning process and plans resources to mitigate any system peak deficits that exist. Demand response program results are measured by the amount of demand reduction, in megawatts (MW), available to the company during system peak periods. According to 2017 U.S. Energy Information Administration (EIA) data, Idaho Power is one of eight investor-owned utilities with greater than 10 percent of their peak load controlled under demand response programs.

Annual DSM Expense Review Filing

On March 15, 2018, Idaho Power filed Case No. IPC-E-18-03 with the Idaho Public Utilities Commission (IPUC) requesting an order finding the company had prudently incurred $44,145,316 in DSM expenses in 2017, including $37,162,002 in Rider expenses, and $6,983,314 in demand response program incentives.

In Order No. 34141, dated September 11, 2018, the IPUC deemed $37,162,002 in Rider expenses, and $6,983,314 in demand response program incentives as prudently incurred.

DSM Programs Performance

The 2018 savings results consisted of 43,651 MWh from the residential sector, 95,759 MWh from the commercial/industrial sector, and 19,002 MWh from the irrigation sector. The Custom Projects option in the Commercial and Industrial (C&I) Energy Efficiency Program contributed 30 percent of Idaho Power's direct program savings, while the residential sector Energy Efficient Lighting and Educational Distributions programs contributed 80 percent of the residential savings and 22 percent of Idaho Power's direct program savings.

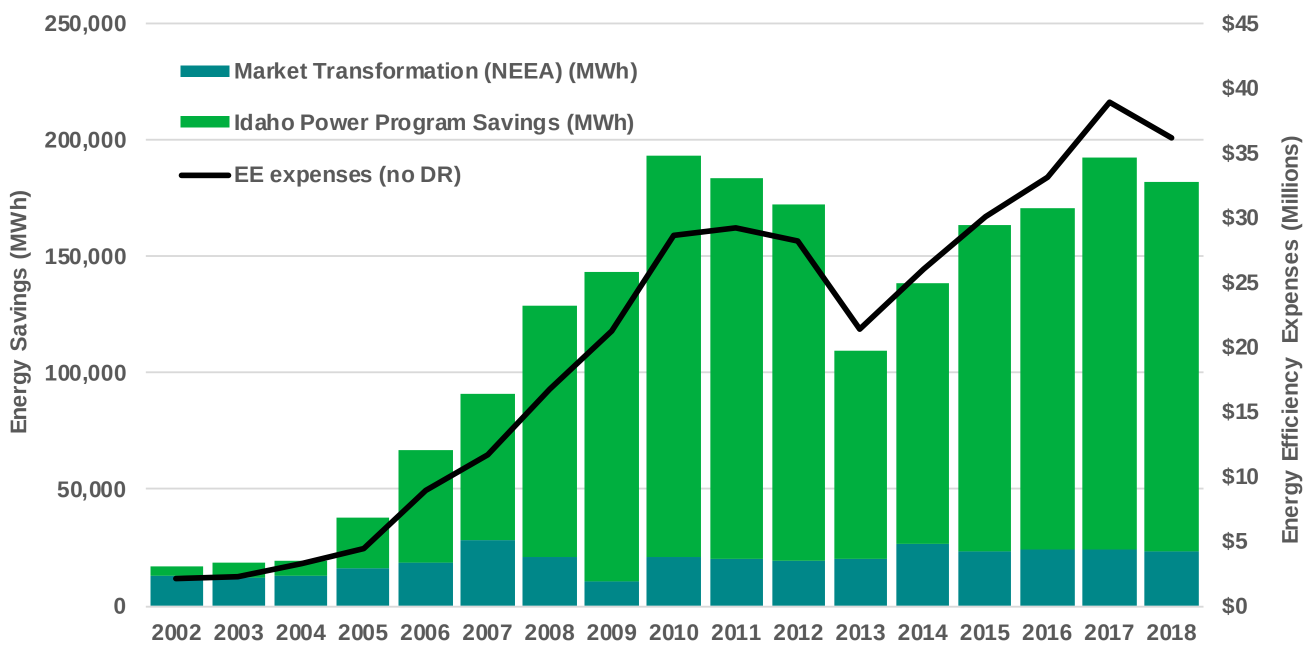


Figure 4. Annual energy savings and energy efficiency program expenses, 2002–2018 (MWh and millions [$])

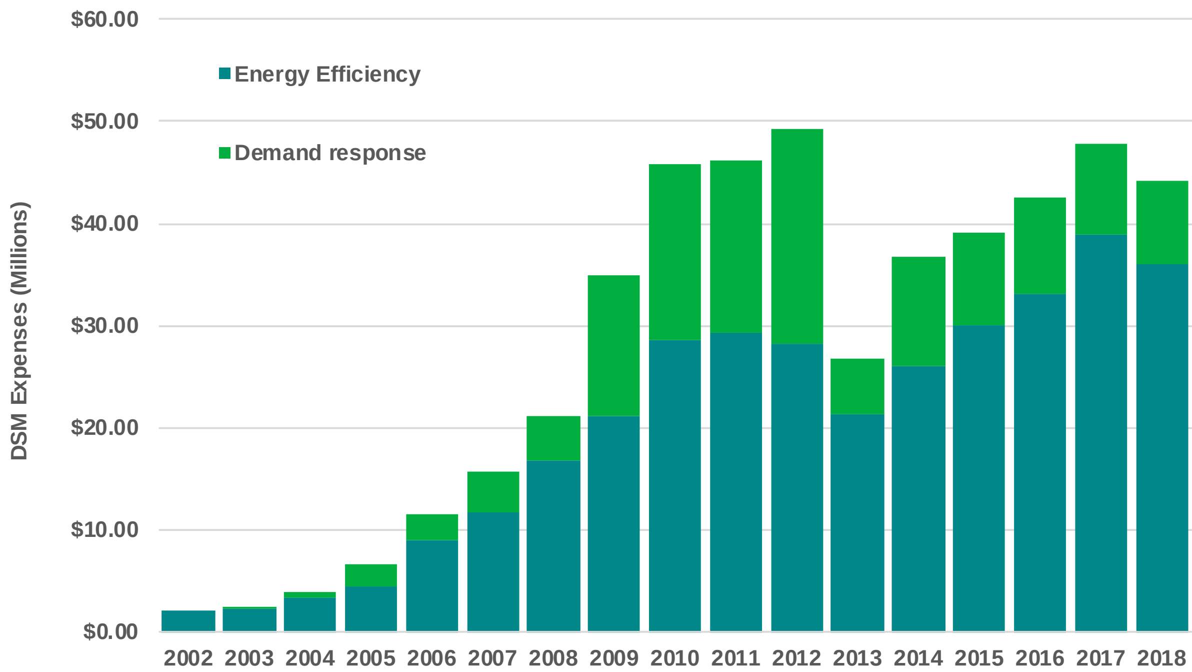


Figure 5. DSM expense history by program type, 2002–2018 (millions [$])

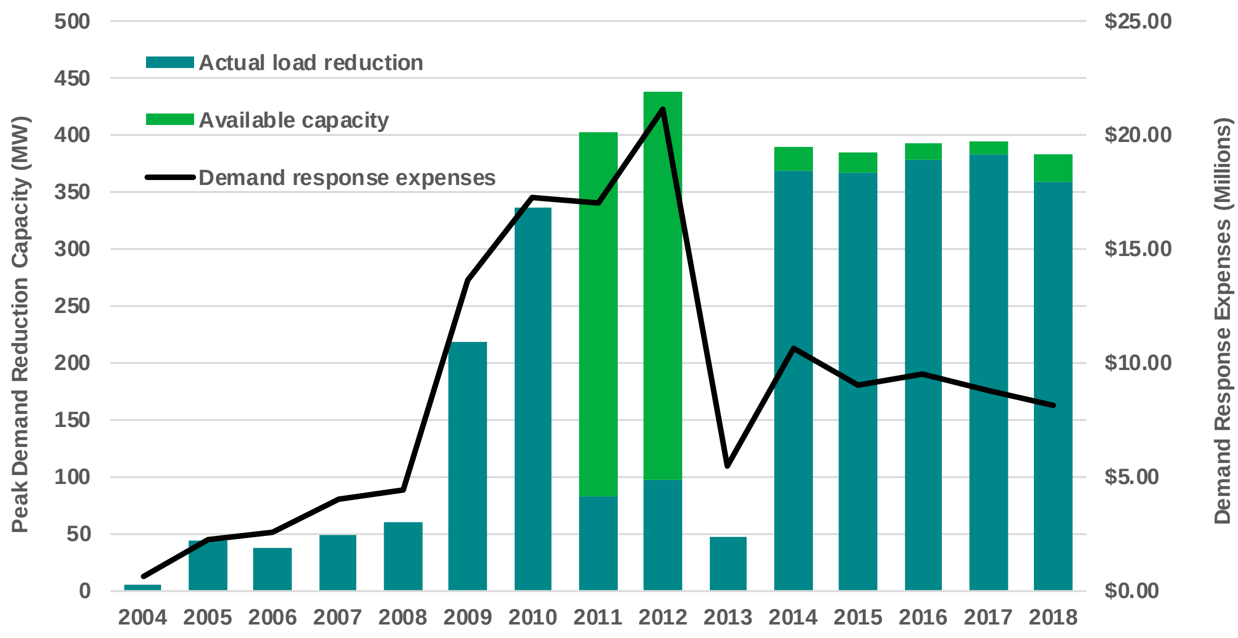


Figure 6. Peak demand-reduction capacity and demand response expenses, 2004–2018 (MW and millions [$])

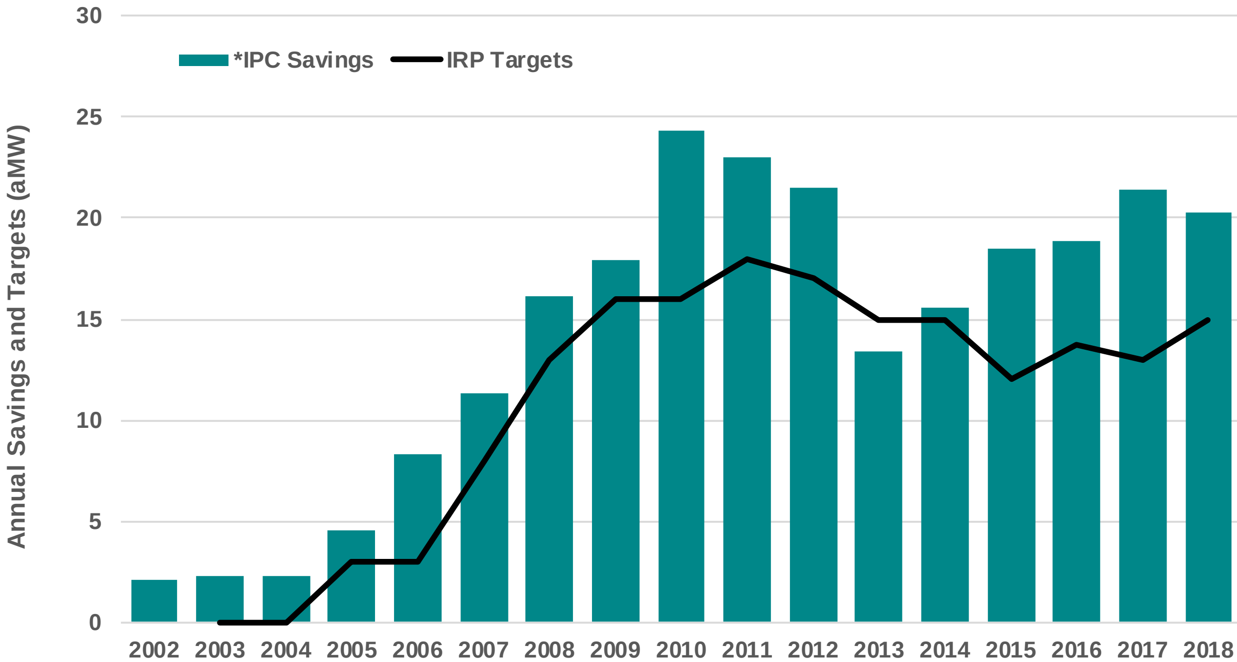


Figure 7. Annual incremental energy efficiency savings (aMW**) compared with IRP targets, 2002–2018
* NEEA codes and standards savings were removed because they are not included in IRP targets
**average megawatt

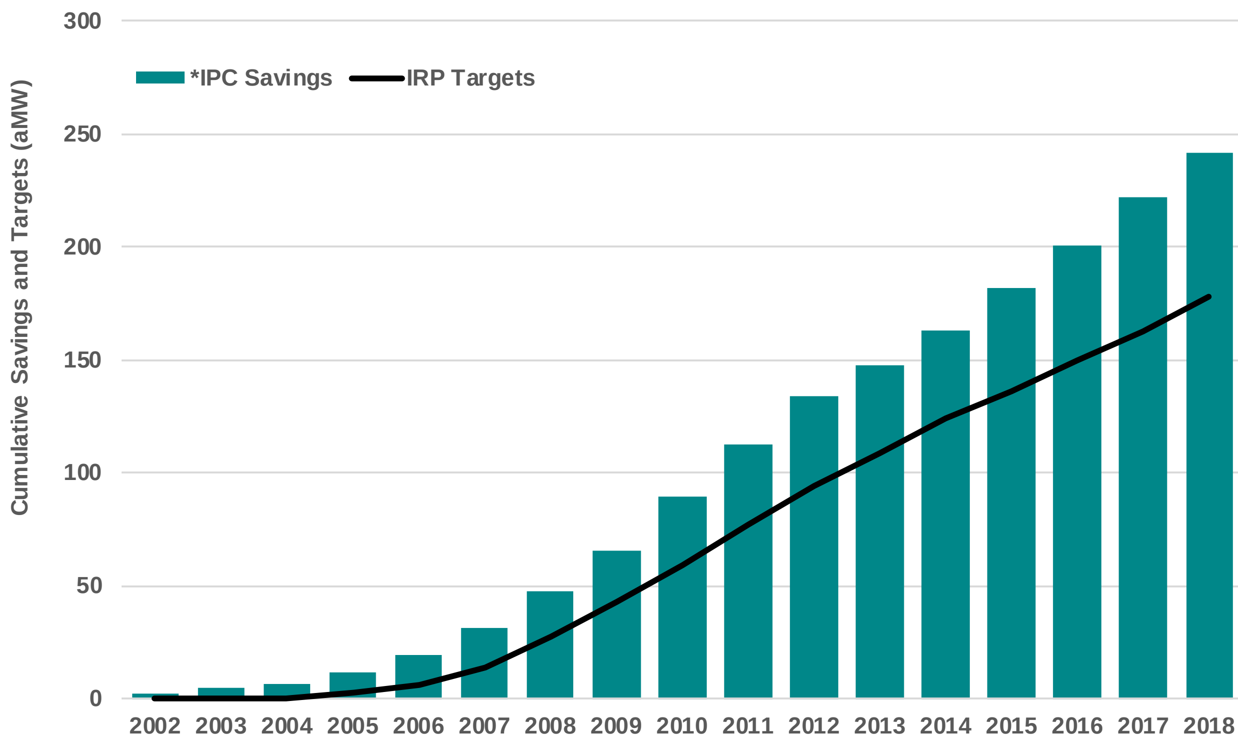


Figure 8. Annual cumulative energy efficiency savings (aMW**) compared with IRP targets, 2002–2018
*NEEA codes and standards savings were removed because they are not included in IRP targets.
**average megawatt

Idaho Power invests significant resources to maintain and improve its energy efficiency and demand response programs. Idaho Power's 2018 achievements in energy savings exceeded the annual savings target identified in Idaho Power's *2017 Integrated Resource Plan*. On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002 (Figure 8).

Demand Response

In summer 2018, Idaho Power had a combined maximum actual non-coincidental load reduction from all three programs of 359 MW at the generation level. The amount of capacity available for demand response varies based on weather, time of year, and how programs are used and managed. The 2018 capacity of demand response programs was 382 MW (Figure 6). The demand response capacity is calculated using total enrolled MW from participants with an expected maximum realization rate for those participants. This maximum realization rate is not always achieved for every program in any given year. The maximum capacity for the Irrigation Peak Rewards program is based on the maximum reduction possible during the hours within the program season. For the Flex Peak Program, the maximum capacity is assumed to be the maximum realized reduction. And for the A/C Cool Credit program, the capacity is calculated based on the number of active participants multiplied by maximum per-unit reduction ever achieved.

Idaho Power has forecast through the IRP that demand response capacity is not currently needed. However, under the terms of IPUC Order No. 32923 and Public Utility Commission of Oregon (OPUC) Order No. 13-482 the company has continued to maintain these programs and use them at least three times per season. In 2018, Idaho Power began conducting analysis and soliciting public input for the 2019 IRP. During this process, the company is analyzing if and when expanded demand response capacity is needed to avoid system peak deficiencies.

Energy Efficiency

Idaho Power's portfolio of energy efficiency program energy savings remains strong in 2018. However, the savings, including the estimated savings from NEEA, slightly decreased to 183,378 MWh compared to the 2017 savings of 192,260 MWh—a 4.6 percent year-over-year decrease. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, was 158,412 MWh in 2018 and 167,819 MWh in 2017—a 5.6 percent year-over year decrease. Even so, the 2018 savings represent enough energy to power over 16,000 average homes in Idaho Power's service area for one year.

In 2018, the company's energy efficiency portfolio was cost effective from both the total resource cost (TRC) test and the utility cost test (UCT) perspectives with ratios of 2.26 and 3.04, respectively. The portfolio was also cost-effective from the participant cost test (PCT) ratio, which was 2.85.

Table 1. DSM programs by sector, operational type, location, and energy savings/demand reduction, 2018

Program by Sector	Operational Type	State	Savings/Demand Reduction
Residential			
A/C Cool Credit	Demand Response	ID/OR	29 MW
Easy Savings: Low-Income Energy Efficiency Education	Energy Efficiency	ID	30 MWh
Educational Distributions	Energy Efficiency	ID/OR	16,052 MWh
Energy Efficient Lighting	Energy Efficiency	ID/OR	18,857 MWh
Energy House Calls	Energy Efficiency	ID/OR	374 MWh
Fridge and Freezer Recycling Program*	Energy Efficiency	ID/OR	74 MWh
Heating & Cooling Efficiency Program	Energy Efficiency	ID/OR	1,556 MWh
Home Energy Audit Program	Energy Efficiency	ID	211 MWh
Home Energy Report Pilot Program	Energy Efficiency	ID	3,282 MWh
Multifamily Energy Savings Program	Energy Efficiency	ID/OR	656 MWh
Oregon Residential Weatherization	Energy Efficiency	OR	0 MWh
Rebate Advantage	Energy Efficiency	ID/OR	285 MWh
Residential New Construction Pilot Program	Energy Efficiency	ID/OR	777 MWh
Shade Tree Project	Energy Efficiency	ID	36 MWh
Simple Steps, Smart Savings™	Energy Efficiency	ID/OR	241 MWh
Weatherization Assistance for Qualified Customers	Energy Efficiency	ID/OR	650 MWh
Weatherization Solutions for Eligible Customers	Energy Efficiency	ID	572 MWh
Commercial/Industrial			
Commercial and Industrial Efficiency Program			
Custom Projects	Energy Efficiency	ID/OR	46,964 MWh
New Construction	Energy Efficiency	ID/OR	13,378 MWh
Retrofits	Energy Efficiency	ID/OR	34,911 MWh
Commercial Energy-Saving Kit	Energy Efficiency	ID/OR	442 MWh
Flex Peak Program	Demand Response	ID/OR	33 MW
Green Motors—Industrial	Energy Efficiency	ID/OR	64 MWh
Oregon Commercial Audits	Energy Efficiency	OR	n/a
Irrigation			
Green Motors—Irrigation	Energy Efficiency	ID/OR	68 MWh
Irrigation Efficiency Rewards	Energy Efficiency	ID/OR	18,934 MWh
Irrigation Peak Rewards	Demand Response	ID/OR	297 MW
All Sectors			
Northwest Energy Efficiency Alliance	Market Transformation	ID/OR	24,966 MWh

* Although the Fridge and Freezer Recycling program was discontinued in 2017, Idaho Power did have a few pickups in 2018.

Table 2. DSM program sector summary and energy usage/savings/demand reduction, 2018

	Energy Efficiency Program Impacts [a]			Idaho Power System Sales		
	Program Expenses	Energy Savings (kWh)	Peak-Load Reduction (MW)[b]	Sector Total (MWh)	Percentage of Energy Usage	Number of Customers
Residential	$ 10,310,503	43,651,278		5,139,473	35%	459,128
Commercial/Industrial	17,014,509	95,759,049		7,471,683	51%	71,222
Irrigation	2,953,706	19,001,507		1,976,587	13%	20,077
Market Transformation	2,500,165	24,966,000				
Demand Response	8,169,419	n/a				
Direct Overhead/ Other Programs	1,978,570	n/a				
Total Direct Program Expenses	**$ 42,926,872**	**183,377,834**		**14,587,743**	**100%**	**550,427**

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] Includes 9.7 percent peak line loss assumptions.

Customer Education

Idaho Power participated in a select group of events impacting large audiences or audiences expected to have a higher receptivity to energy-efficient messaging and behavior change. Idaho Power additionally participated in or sponsored 45 outreach activities, including events, presentations, trainings, and other activities. Idaho Power customer representatives throughout the service area delivered numerous other presentations to local organizations addressing energy efficiency programs and wise energy use. In 2018, Idaho Power's community education team provided 118 presentations on *The Power to Make a Difference* to 3,063 students and 122 classroom presentations on *Saving a World Full of Energy* to 2,803 students. The community education representatives and other staff also completed 24 presentations to senior citizen groups on energy efficiency programs and shared information about saving energy to 1,149 senior citizens in the company's service area.

Since 2008, the company's commercial and industrial training activities have informed and educated commercial and industrial customers regarding energy efficiency, increased awareness of and participation in existing energy efficiency and demand response programs, and enhanced customer satisfaction regarding energy efficiency initiatives. The level of participation in 2018 remained high, with 337 attendees for the technical sessions and almost 90 for the program workshops. The workshops covered the following topics: Commercial/Industrial Motor Efficiency; Commercial/Industrial Adjustable Speed Drives; Compressed Air Challenge Level II—Advanced Management of Compressed Air Systems; Energy Efficiency of Chilled Water Systems; Energy Efficiency of Cooling Towers; Advanced Lighting Control Systems; Energy Efficient Data Center; Industrial Refrigeration Systems Energy Management; Heating, Ventilation, and Air Conditioning (HVAC) Controls Training; and Optimizing Pumping Systems: A Measurement-Based Approach.

Surveying Customer Satisfaction

Idaho Power fields a variety of customer surveys throughout the program year. Some of these are overall customer satisfaction or relationship surveys and others measure customer satisfaction related to specific program offerings. Depending on the nature of the research, these surveys are typically conducted by telephone, online, or through the mail. Surveys are conducted internally or by third-party research vendors. Internally conducted surveys are managed by the customer relations and research coordinator with oversight by program specialists and/or the marketing department.

Based on surveys conducted in the last six months of 2017 and the first six months of 2018, Idaho Power ranked second out of 14 utilities included in the west region midsize segment of *the J.D. Power and Associates 2018 Electric Utility Residential Customer Satisfaction Study*. Fifty-two percent of the residential respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and on an overall basis, those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

Burke, Inc., conducts quarterly customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power among all customer segments. The Burke Customer Relationship Survey measures the satisfaction of a number of aspects of a customer's relationship with Idaho Power, including energy efficiency at a very high level. However, the survey is not intended to measure all aspects of energy efficiency programs offered by Idaho Power.

The 2018 results of Idaho Power's customer relationship survey showed record high overall customer satisfaction including an increase in meeting and exceeding customers' needs by encouraging energy efficiency. Sixty-seven percent of customers indicated their needs were met or exceeded by Idaho Power encouraging energy efficiency among its customers. Figure 9 depicts the percent of customers who indicated Idaho Power met or exceeded their needs concerning the energy efficiency efforts it encouraged each year since 2009.

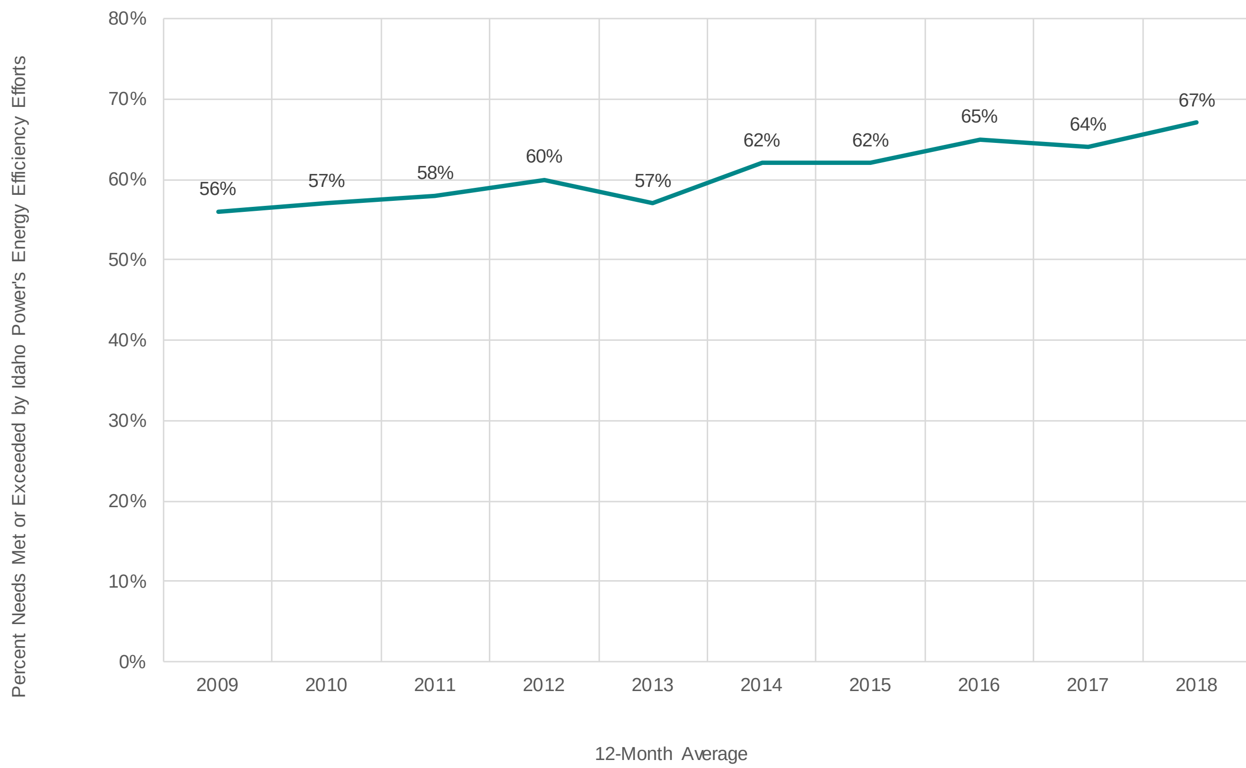


Figure 9. Customers' needs "met" or "exceeded" (percent), 2009–2018

The 2018 survey also asked three questions related to Idaho Power's energy efficiency programs: 1) Have you participated in any of Idaho Power's energy efficiency programs? 2) Which energy efficiency program did you participate in? and 3) Overall, how satisfied are you with the energy efficiency program? In 2018, 45 percent of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program, and 92 percent were “very” or “somewhat” satisfied with the program they participated in.

Results of sector-level, program-level, and/or marketing-related customer satisfaction surveys can be found later in this report.

Program Evaluation Approach

Idaho Power considers program evaluation an essential component of its DSM operational activities. The company uses third-party contractors to conduct impact, process, and other evaluations on a scheduled and as-required basis. In some cases, research and analyses are conducted internally and managed by Idaho Power’s Research and Analysis team within the Customer Relations and Energy Efficiency (CR&EE) department. Third-party evaluations are specifically managed by the company’s energy efficiency evaluator. Third-party contracts are generally awarded using a competitive-bid process managed by Idaho Power’s Corporate Services department.

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.

The company also supports regional and national studies to promote the ongoing cost-effectiveness of programs, the validation of energy savings and demand reduction, and the efficient management of its programs. Idaho Power considers primary and secondary research, cost-effectiveness analyses, potential assessments, and impact and process evaluations to be important resources in providing accurate and transparent program-savings estimates. Idaho Power uses recommendations and findings from evaluations, research, and industry best practices to continuously refine its DSM programs.

For a summary of evaluation results, recommendations, and responses, see each program section. For copies of 2018 program evaluation reports and past and future evaluation schedules, see *Supplement 2: Evaluation*.

Cost-Effectiveness Goals

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. Idaho Power’s energy efficiency and demand response opportunities are preliminarily identified through the IRP process. Idaho Power uses third-party energy efficiency potential studies to identify achievable cost-effective energy efficiency potential that is added to the resources included in the IRP. Because of Idaho Power’s diversified portfolio of programs, most of the new potential for energy efficiency in its service area is based on additional measures to be added to existing programs, rather than developing new programs.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design or measure will be cost-effective from the perspective of Idaho Power and its customers. Incorporated in these models are inputs from various sources that use the most current and reliable information available.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the TRC test, UCT test, and PCT at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test provides value when evaluating program performance. If a measure or program is found to be not cost-effective from one or more of the three tests, Idaho Power assesses the program or measure and runs the cost-effectiveness calculations under a variety of scenarios. There are many assumptions when calculating the cost-effectiveness of a given program or measure. For some measures within the programs, savings can vary based on factors, such as participation levels or the participants' locations. For instance, heat pumps installed in the Boise area will have less savings than heat pumps installed in the McCall area. If program participation and savings increase, fixed costs, such as labor and marketing, are distributed more broadly, and the program cost-effectiveness increases.

When a program or measure is shown to be not cost-effective, Idaho Power works with the Energy Efficiency Advisory Group (EEAG) to obtain input before making its determination on continuing or discontinuing an offering. If the measure or program is indeed offered, the company explains to EEAG and stakeholders why the measure or program was implemented or continued and the steps the company plans to take to improve its cost-effectiveness. The company believes this aligns with the expectations of the IPUC and OPUC.

As part of the public workshops on Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new methodology for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923 and OPUC Order No. 13-482, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours to be no more than $16.7 million. The annual value calculation will be updated with each IRP based on changes that include, but are not limited to, need, capital cost, or financial assumptions. This amount was reevaluated in the 2015 IRP to be $18.5 million. Under the 2017 IRP, this value is $19.8 million.

This value is the levelized annual cost of a 170-MW deferred resource over a 20-year life. The demand response value calculation will include this value even in years when the IRP shows no peak-hour capacity deficits. In 2018, the cost of operating the three demand response programs was $8.2 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $11.3 million and would have remained cost-effective. The settlement agreement also allowed Idaho Power to design its programs such that they can be dispatched three times a year with no variable costs. This is what Idaho Power normally does unless the capacity is needed to meet load.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

Energy Efficiency Advisory Group

Formed in 2002, EEAG provides input on enhancing existing DSM programs and on implementing energy efficiency programs. Currently, EEAG consists of 13 members from Idaho Power's service area and the Northwest. Members represent a cross-section of customers from the residential, industrial, commercial, and irrigation sectors, and technical experts, as well as representatives from low-income households, environmental organizations, state agencies, county and city governments, public utility commissions, and Idaho Power.

EEAG meets quarterly and, when necessary, Idaho Power facilitates conference calls and/or webinars to address special topics. In 2018, four EEAG meetings were held: February 8, May 1, August 9, and October 30. EEAG meetings are generally open to the public and attract a diverse audience. Idaho Power appreciates the input from the group and acknowledges the commitment of time and resources the individual members give to participate in EEAG meetings and activities.

During these meetings, Idaho Power discussed new energy efficiency program ideas and new measure proposals, marketing methods, and specific measure details. The company provided the status of energy efficiency expenses and Idaho and Oregon Rider funding, gave updates of ongoing programs and projects, and supplied general information on DSM issues and other important issues occurring in the region. Experts were invited to speak about evaluations, research, and other topics of interest.

Idaho Power relies on input from EEAG to provide a customer and public-interest view of energy efficiency and demand response. Additionally, Idaho Power regularly provides updates on current and future cost-effectiveness of energy efficiency programs and the changes in IRP provides updates on DSM alternate costs, which Idaho Power uses in calculating cost-effectiveness. In each meeting, Idaho Power requests feedback from EEAG members on energy efficiency and demand response programs, specific measures, and incentives. EEAG often recommends presentation ideas for future meetings.

Throughout 2018, Idaho Power relied on input from EEAG on the following important topics.

Residential Energy-Saving Kits

The deemed savings that had been previously applied to the Giveaway Energy-Saving Kits (ESK) were no longer being supported by the RTF, and the new deemed savings did not apply to the Giveaway ESKs as designed. Idaho Power presented options on how to manage the giveaways moving forward, including changing the kits to match the savings that were supported by the RTF or keeping the ESKs as-is and continuing to apply the previous savings. EEAG agreed the company should continue to distribute Giveaway ESKs to customers who call about their high bills and at various events, while continuing to apply the previous deemed savings. EEAG agreed this effort should be continued as this interaction is targeted to a more engaged customer.

Simple Steps, Smart Savings

Idaho Power reported to EEAG that the incremental price difference between standard and high efficiency showerheads had become small and asked the group if the company should continue with incentives for this measure. The group suggested the company should consider market indicators before deciding whether to continue offering this measure. Based on EEAG's feedback and findings from researching the market that indicated inefficient showerheads are still available, the group recommended the company should continue offering these showerheads as part of the program.

School Cohort

EEAG was asked for input regarding continuation with year-two of the School Cohort. The group expressed appreciation that the company is looking for ways to improve and continue this program. The consensus of the group was that Idaho Power should continue this effort for the second year.

A/C Cool Credit

The company informed EEAG that it was unable to communicate with a small number of load control devices and it committed to develop a plan to test these devices. The company provided detailed information regarding the proposed testing protocol and explained that, as a last resort, participants would be removed from the program if reliable communication could not be established. After further discussion, the group was in favor of Idaho Power moving forward with the new testing protocol.

Smart-Saver Pledge

At the October 2017 meeting, Idaho Power updated EEAG regarding the status of the 2018 campaign. Previously, EEAG members were asked to work in groups to help Idaho Power come up with new low-cost or no-cost items to use in the pledge. As a result, four out of the five items listed on the 2018 pledge form came from that break out session.

Idaho Power Field Staff

Idaho Power has a wide array of field personnel who have regular and almost continual contact with its customers provide this service throughout the Idaho Power service area. These expert energy advisors include: major account and combo representatives, customer representatives, agriculture representatives, community education representatives, and customer solutions advisors. All the representatives are subject-matter experts in their respective fields and provide added support for customers through strong working relationships. These representatives promote Idaho Power’s energy efficiency programs and help customers to use energy wisely.

Future Plans for DSM Programs

Idaho Power will continue to pursue all prudent cost-effective energy and an appropriate amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecast level of energy efficiency and the needed level of demand response are determined by Idaho Power’s biennial IRP planning process. Idaho Power includes all achievable cost-effective energy savings as identified in its potential studies in each IRP and considers this achievable potential a reasonable 20-year planning estimate. However, the company does not consider the achievable potential as a ceiling limiting energy efficiency acquisition. The IRP is developed in a public process that details Idaho Power’s strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency to develop a preferred portfolio of future resources to meet the specific energy needs of Idaho Power’s customers.

The company will explore new energy-savings potential through third-party resources, conferences, and regional organizations, and will continue to assess and develop new program offerings through its Program Planning Group (PPG). Idaho Power will work in consultation with EEAG to expand or modify its energy efficiency portfolio. Future plans for individual programs are included under each program's *2019 Program and Marketing Strategies* section.

In 2018, Idaho Power will continue to enhance its marketing and outreach efforts as described in the Marketing section of this report and within each program section. Idaho Power will continue to work with NEEA on its market transformation activities during the 2015–2019 funding cycle and will participate in discussions with NEEA concerning its 2020–2024 funding cycle.

The company will complete its research and evaluation, measurement, and verification (EM&V) projects included in the evaluation plan in *Supplement 2: Evaluation*.

DSM Annual Report Structure

The *Demand-Side Management 2018 Annual Report* consists of this main document and two supplements.

The main document contains the following sections related to 2018 DSM activities: 1) program activities by customer sector (residential, commercial/industrial, and irrigation) including marketing efforts, cost-effectiveness analysis, customer satisfaction survey results, and evaluation recommendations and responses for each program; 2) other program and activity details including market transformation; 3) and four appendices of data related to payments, funding, and program-level costs and savings. Where appropriate, plans for 2019 are also discussed. Historical data related to energy efficiency programs and demand response activities that was traditionally reported in Appendix 4, has been moved to *Supplement 2: Evaluation* in the *Other* section.

Supplement 1: Cost-Effectiveness describes the standard cost-effectiveness tests for Idaho Power programs and reports current-year program-level and summary cost-effectiveness and expenses by funding source and cost category.

Supplement 2: Evaluation includes an evaluation and research summary, an evaluation plan, EEAG meeting notes, links to NEEA evaluations, and copies of Integrated Design Lab (IDL) reports, research and survey reports, evaluation reports, and other reports (including the historical program data mentioned above).

2018 DSM Program Activity

DSM Expenditures

Funding for DSM programs in 2018 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. The 2018 Idaho Rider was 3.75 percent of base revenues. On November 9, 2018 Idaho Power filed Advice No. 18-10 with the OPUC to increase the Oregon Rider collection percentage from 3 percent to 4 percent of base revenues. Concurrently, Idaho Power filed Advice No. 18-11 to lower the collection percentage of the Solar Photovoltaic Pilot Program Rider, and in both advice filings requested to transfer $5.5 million from the Solar Photovoltaic Pilot Program Rider balance to the Oregon Rider balance. Both advice filings received OPUC approval on December 18, 2018. Additionally, Idaho demand response program incentives were paid through base rates and the annual PCA mechanism. DSM expenses not funded through the Rider are included as part of Idaho Power's ongoing operation and maintenance (O&M) costs.

Total DSM expenses funded from all sources were $44.3 million in 2018. At the beginning of 2018, the Idaho Rider balance was approximately $0.4 million, and by December 31, 2018, the positive balance was $5.3 million. At the beginning of 2018, the Oregon Rider negative balance was approximately $6.3 million, and by year-end, the negative balance was $1.4 million.

Table 3 shows the total expenditures funded by the Idaho and Oregon riders and non-rider funding resulting in Idaho Power's total DSM expenditures of $44,262,080. The non-rider funding category includes the company's demand response Idaho incentives, Weatherization Assistance for Qualified Customers (WAQC) expenses, and O&M costs.

Table 3. 2018 funding source and energy savings

Funding Source	Expenses	MWh Savings
Idaho Rider	$ 33,663,001	176,204
Oregon Rider	1,757,910	6,524
Idaho Power Base Rates	8,841,168	650
Total	**$ 44,262,080**	**183,378**

Table 4 and Figure 10 indicate 2018 DSM program expenditures by category. The Materials & Equipment category includes items that directly benefit customers: ESKs and LED lightbulbs distributed at customer events ($2,255,883) and direct-install weatherization measures ($125,000). The expenses in the Other Expense category include marketing ($1,270,112), program evaluation ($97,448), program training ($168,278), and Custom Projects energy audits ($259,821). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs.

Table 4. 2018 DSM program expenditures by category

	Total	% of Total
Incentive Expense	$ 25,114,246	57%
Labor/Administrative Expense	3,867,974	8%
Materials & Equipment	2,638,648	6%
Other Expense	2,148,339	5%
Purchased Services	10,492,873	24%
Total 2018 DSM Expenditures by Category	**$ 44,262,080**	**100%**

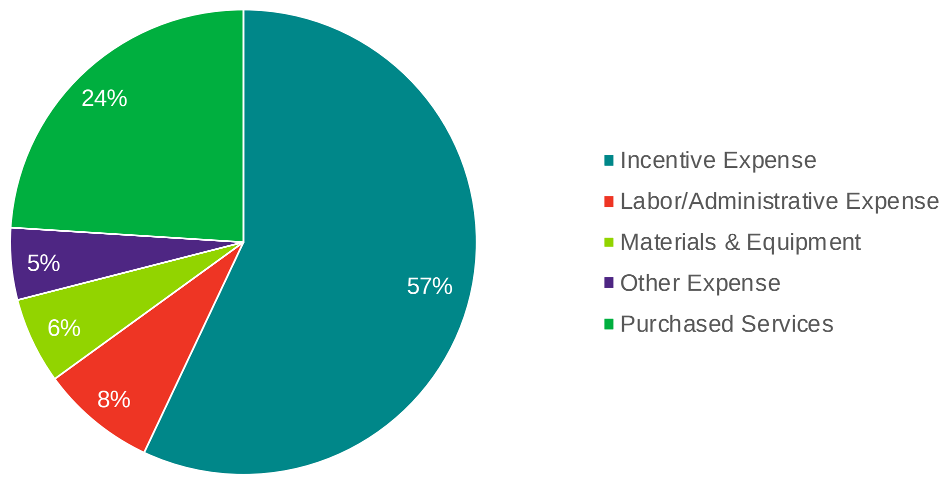


Figure 10. 2018 DSM program expenditures by category

Table 5. 2018 DSM program incentive totals by program type and sector

Program Type—Sector	Total	% of Total
DR[a]—Residential	$ 379,237	2%
DR—Commercial/Industrial	371,496	1%
DR—Irrigation	6,636,510	26%
EE[b]—Residential	2,029,822	8%
EE—Commercial/Industrial	13,180,964	53%
EE—Irrigation	2,516,217	10%
Total Incentive Expense	**$ 25,114,246**	**100%**

[a] DR = demand response
[b] EE = energy efficiency

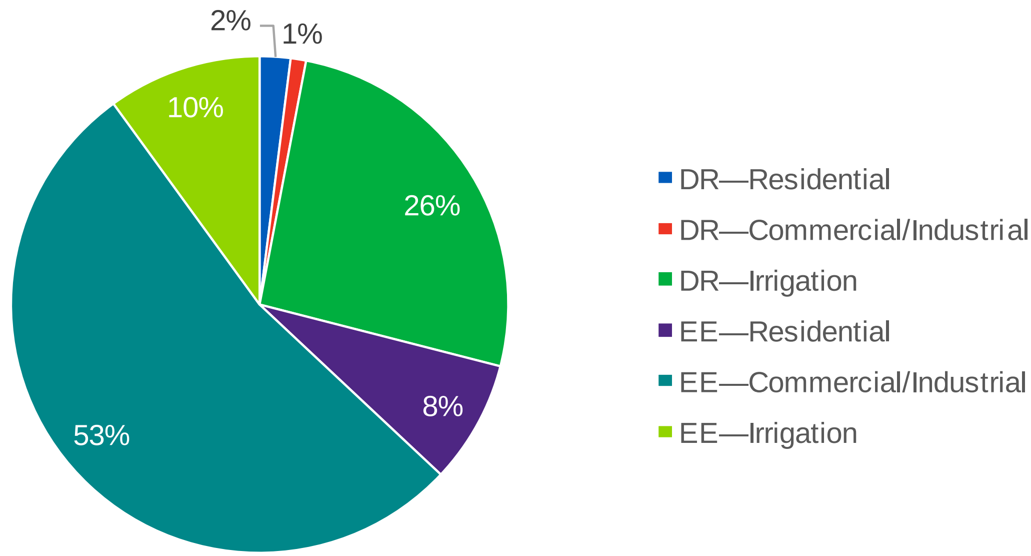


Figure 11. DSM program incentives by segment and sector, 2018

Marketing

Idaho Power used multi-channel marketing and public relations strategies in 2018 to improve communication and increase energy efficiency program awareness among its customers. Idaho Power uses a wide variety of media and marketing. Owned media (social, website, and newsletters) and paid media (advertising and sponsorships) allow Idaho Power to control content. Earned unpaid media (news coverage, Idaho Power's *News Briefs* sent to reporters, third-party publications, and television news appearances) give Idaho Power access to audiences through other channels and help establish credibility and brand trust. Though Idaho Power has less control of the content with earned unpaid media, the value is established from the third-party endorsement.

The following describes a selection of the methods, approaches, and strategies used by Idaho Power to engage with customers regarding energy efficiency, along with their results. See the respective Sector Overviews and program sections later in this report for the company's marketing efforts specific to those areas.

Social Media

Approximately 25 percent of the company's total social media content promoted energy efficiency in 2018. Idaho Power regularly posted messages encouraging energy efficiency behaviors, program enrollment, and customer engagement on Facebook, Twitter, YouTube, and LinkedIn. Social media content also showcased local businesses and organizations that have benefitted from Idaho Power energy efficiency efforts. Idaho Power engaged with customers posting their own social media content about Idaho Power programs such as Energy-Saving Kits and Welcome Kits.

Figure 12. Idaho Power shares energy efficiency tips and engages with customers on social media.

In 2018, Idaho Power continued its *#TipTuesday* posts on Facebook and Twitter. *#TipTuesday* posts provided Idaho Power's Facebook and Twitter followers with an energy efficiency tip or program information every Tuesday of the year, with the exception of a brief hiatus in September while the team worked to update design and strategy. The posts used photos and included the hashtag *#TipTuesday* so the tips could be categorized together and easily identified by social media users. For the first time, the company paid to "boost" a few *#TipTuesday* posts to increase reach to Idaho Power Facebook followers and their friends. Facebook charges a fee to boost a post to target specific audiences.

Idaho Power's Facebook followers increased 9.6 percent in 2018, from 17,645 at the end of 2017 to 19,340 at the end of 2018. Though the number of followers increased overall, the rate Idaho Power added followers is slightly lower in 2018 because Facebook changed to an algorithm that promotes interactions from friends and family over content from businesses or brands. In this new Facebook environment, it is harder to reach followers or gain new followers without paying for advertising.

Idaho Power uses Twitter to communicate with customers, the media, and business partners about media items, large outages, and energy efficiency. Idaho Power's Twitter followers increased 5 percent in 2018, from 5,510 followers to 5,785. Twitter growth is a lower priority for Idaho Power, as Facebook is a much more widely used and more popular platform for engaging directly with all customer demographics.

Idaho Power saw a very favorable increase in followers on LinkedIn: up 24 percent from 2017. The increase is attributed to a concerted effort to engage business and commercial customers in energy efficiency on LinkedIn, as well as position the company as a good corporate citizen and employer of choice.

Website

Idaho Power tracked the number of page views to the main energy efficiency pages—also known as landing pages—on the company's website. In 2018, the company's energy efficiency homepage received 35,326 page views, the residential landing page received 213,183, and the business and irrigation landing pages received 13,394. Idaho Power uses Google Analytics to analyze web activity. Google's definition of page views is the total number of pages viewed, with repeated views of a single page by one user counted as a new view.

Bill Inserts

A February bill insert promoting Idaho Power's Empowered Community, which is often surveyed on topics related to energy efficiency, was sent to 329,379 customers. Read more about the Empowered Community in the Residential Sector Overview. Other program-specific bill inserts were also sent throughout the year. Information about those can be found in each program later in this report.

Public Relations

Idaho Power's public relations (PR) staff supported energy efficiency programs and activities through multiple channels: *eNews* videos telling energy efficiency success stories; *Connections*, a monthly customer newsletter distributed in approximately 410,000 monthly bills and available online; *News Briefs*, a weekly email of interesting news items sent to all media in the company's service area; pitching and participating in news stories; energy efficiency TV segments in three markets (KTVB in Boise, KPVI in Pocatello, and KMVT in Twin Falls); news releases; and public events (such as incentive check presentations).

In 2018, the April and October issues of *Connections* were devoted to energy efficiency. The April issue included stories about Idaho Power's heat pump water heater (HPWH) incentive for residential customers, the winners of the 2017 Smart-Saver Pledge contest, and an energy-saving success story at Alpine Automotive in McCall. The October edition of *Connections* focused on fixing leaks to keep homes cozy, the benefits of Home Energy Audits, and the kickoff of the 2018 Smart-Saver Pledge.

Idaho Power produced a number of videos championing energy efficiency in 2018. Examples include wintertime energy savings tips; ductless heat pumps (DHP); energy-savings success at Alpine Automotive in McCall, Roaring Springs and Wahooz in Meridian, and the Pocatello School District; the Multifamily Energy Saving Program; and a series of quick tip for social media. Collectively, energy efficiency videos posted in 2018 received more than 2,700 views on YouTube and an additional 5,600 views on Facebook.

The monthly energy efficiency television segments continued to receive positive feedback. Topics included energy-saving New Year's resolutions, Energy-Saving Kits, energy efficient spring planting, ways to beat the summer heat, and energy efficient holiday cooking and decorating. Idaho Power representatives conducted the energy efficiency segments on stations in Boise, Twin Falls and Pocatello.

In Pocatello, the station discontinued regular monthly segments because of a format change late in the year, but a customer representative made several TV appearances and was interviewed on the radio for topics related to energy efficiency in October and November.

Figure 13. Idaho Power appearances on KTVB and KMVT

Media outreach efforts resulted in a variety of earned media coverage focused on energy efficiency. Energy efficiency topics were pitched in *News Briefs* throughout the year, and the company earned media coverage in multiple markets spanning print, TV, and radio. Some of the most popular story topics included winter savings tips in January, a large incentive check for SUEZ Water in September, and Idaho Power receiving the Governor’s Award for Excellence in Energy Efficiency in October.

Staff Activities

Idaho Power staff networks with organizations across the region and industry to ensure it is informed about current and future marketing trends and successes. NEEA and Idaho Power staff held regular meetings throughout 2018 to coordinate, collaborate, and facilitate marketing for all sectors. All marketing activities were reviewed for progress, results, and collaborative opportunities.

To build marketing networks and to learn what works in other regions, Idaho Power staff attended the E Source Utility Marketing Executive Council and E Design Conference in April and the E Source Utility Marketing Executive Council and Forum in September.

2019 Marketing Activities

In 2019, the Idaho Power marketing department plans to introduce new strategies to expand the reach and visibility of the company’s energy efficiency ads.

The marketing team will update the Residential Energy Efficiency Awareness Campaign and consider running it on new digital platforms. Idaho Power will continue to support various business organizations and programs focused on promoting energy efficiency and will explore radio advertisements and additional resources targeted toward small businesses. Additionally, the company will continue to update collateral and displays for irrigation programs and trade shows.

See the Sector Overviews for more specific marketing plans for the future.

Cost-Effectiveness Results

In 2018, 18 individual measures in various program are shown to be not cost-effective from either the UCT or TRC perspective. These measures will be discontinued, analyzed for additional non-energy benefits (NEB), modified to increase potential per-unit savings, or monitored to examine their impact on the specific program's overall cost-effectiveness.

Most of Idaho Power's energy efficiency programs were cost-effective from the perspective of all tests, except for the Heating and Cooling Efficiency (H&CE) Program, Shade Tree Project, and the weatherization programs for income-qualified customers.

Heating & Cooling Efficiency Program

The H&CE Program has a UCT of 1.65, TRC of 0.83, and PCT of 1.50. In 2016, Idaho Power reviewed the program's cost-effectiveness and notified EEAG at the August 30, 2016, meeting that the program was anticipated to be not cost-effective from the TRC perspective. Idaho Power has continued to update EEAG of its efforts to improve the program's cost-effectiveness.

Throughout 2017 and into 2018, Idaho Power worked toward improving program cost-effectiveness. These tactics included: 1) reassigning non-program labor, 2) reducing marketing spend while optimizing campaigns, 3) reducing contractor incentives from $150 to $50, and 4) adding heat pump water heaters to the program. These efforts were successful in keeping cost-effectiveness ratios from falling in 2018 over 2017 levels. However, calibrations to end-use load shapes created for the 2016 energy efficiency potential study offset cost-effectiveness gains from cost control efforts in 2018. Had Idaho Power used the same load shape as was used for the 2017 program year, the program would have had a TRC just over 1.0.

Shade Tree Project

The Shade Tree Project has a UCT of 0.71, a TRC of 0.80. The cost-effectiveness for the program is based on the modeled savings for the tree distributed in 2018 and the costs incurred during 2018. It is estimated that these trees will begin saving 35,425 kWh in 2022 and 116,197 kWh by year 2038.

The shade tree calculator assumes a measure life of 20 years for the average tree. However, the most common tree species distributed in 2018 have an average life of 50 to 500 years according to the United States Department of Agriculture and the Urban Forest Ecosystem Institute. While the savings beyond 2038 are unknown, if the energy savings were to stay constant beyond year 20, it can be assumed the program would be cost-effective from both the UCT and TRC perspective if the program life was revised to 30 years.

Weatherization Programs

The WAQC program had a TRC of 0.52 and a UCT ratio of 0.43, and the Weatherization Solutions for Eligible Customers (Weatherization Solutions) program had a TRC of 0.51 and a UCT ratio of 0.37. The programs showed a slight increase in cost-effectiveness ratios over 2017. However, the cost-effectiveness ratios will decline slightly again in 2019 with the full adoption of the 2017 IRP DSM alternate costs. Also in 2019, both WAQC and Solutions will have updated per-home savings based on a billing analysis of the homes weatherized between 2015–2017.

Table 6. Cost-effectiveness summary by energy efficiency program

Program/Sector	UCT	TRC	Ratepayer Impact Measure (RIM)	PCT
Educational Distributions	2.68	4.51	0.58	N/A
Energy Efficient Lighting	4.67	6.64	0.59	13.05
Energy House Calls	1.37	1.74	0.42	N/A
Heating & Cooling Efficiency Program	1.65	0.83	0.47	1.50
Multifamily Energy Savings Program	1.60	3.00	0.47	N/A
Rebate Advantage	1.93	1.08	0.45	2.09
Residential New Construction Pilot Program	2.51	1.23	0.59	1.97
Shade Tree Project	0.71	0.80	0.57	N/A
Simple Steps, Smart Savings	1.44	4.68	0.48	8.54
Weatherization Assistance for Qualified Customers	0.43	0.52	0.25	N/A
Weatherization Solutions for Eligible Customers	0.37	0.51	0.22	N/A
Residential Energy Efficiency Sector	**2.37**	**3.16**	**0.54**	**10.03**
Commercial and Industrial Energy Efficiency Program				
Custom Projects	3.85	2.32	1.18	1.92
New Construction	3.97	1.79	0.89	1.88
Retrofits	3.58	1.45	0.87	1.55
Commercial Energy-Saving Kits	1.56	2.50	0.65	N/A
Commercial/Industrial Energy Efficiency Sector *	**3.75**	**1.87**	**1.01**	**1.76**
Irrigation Efficiency Rewards	4.57	3.03	1.29	2.73
Irrigation Energy Efficiency Sector **	**4.60**	**3.04**	**1.29**	**2.73**
Energy Efficiency Portfolio	**3.04**	**2.26**	**0.83**	**2.85**

* Commercial/Industrial Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors Rewinds.
** Irrigation Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors Rewinds.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction Surveys

Idaho Power does not separately survey most energy efficiency program participants each year. This is primarily due to a concern of over-surveying program participants and because the measures and specifics of most program designs do not change annually. To ensure meaningful research in the future, Idaho Power conducts program research periodically (every two to three years), unless there have been major program changes. Throughout 2018, Idaho Power administered several surveys regarding energy efficiency programs to measure customer satisfaction. Some surveys were administered by a third-party contractor; other surveys were administered by Idaho Power either through traditional paper or electronic surveys or through the company's Empowered Community online survey. Results of these studies are included in *Supplement 2: Evaluation*.

The sector-level results of the *2018 Burke Customer Relationship Survey* are available in each Sector Overview of this report: Residential, Commercial and Industrial, and Irrigation.

Evaluations

In 2018, Idaho Power contracted with Tetra Tech MA to conduct three program impact evaluations and one program process evaluation, DNV GL to conduct a program savings determination analysis, Resource Action Programs to conduct two program summary analyses, and Aclara to conduct one program summary analysis. Impact evaluations were performed for Energy Efficient Lighting, Multifamily Energy Savings Program, and the Custom option of the Commercial and Industrial Energy Efficiency Program. A process evaluation was performed for the Multifamily Energy Savings Program and a savings determination analysis was conducted for the Shade Tree Project. Program summary analyses were performed for the Energy-Saving Kit Program, the Energy Wise Program, and the Home Energy Report pilot project. Idaho Power conducted internal analyses of the 2018 demand response events for A/C Cool Credit, Irrigation Peak Rewards, and Flex Peak Program.

A summary of each of these evaluations is available in the respective program section. An evaluation schedule and the final reports from evaluations and research completed in 2018 are provided in *Supplement 2: Evaluation*.

Residential Sector Overview

Idaho Power's residential sector consists of 460,717 customers; Idaho customers number 447,282 and eastern Oregon has 13,435. In 2018, the number of residential sector customers increased by 10,328, an increase of 2.3 percent from 2017. The residential sector represented 35 percent of Idaho Power's actual total electricity usage and 44 percent of overall revenue in 2018.

Table 7 shows a summary of 2018 participants, costs, and savings from the residential energy efficiency programs.

Table 7. Residential sector program summary, 2018

			Total Cost		Savings	
Program	**Participants**		**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response						
A/C Cool Credit	26,182	homes	$ 844,369	$ 844,369		29
Total			**$ 844,369**	**$ 844,369**		**29**
Energy Efficiency						
Easy Savings: Low-Income Energy Efficiency Education	282	HVAC tune-ups	$ 147,936	$ 147,936	29,610	
Educational Distributions	94,717	kits/giveaways	3,180,380	3,180,380	16,051,888	
Energy Efficient Lighting	1,340,842	lightbulbs	2,435,130	3,277,039	18,856,933	
Energy House Calls	280	homes	160,777	160,777	374,484	
Fridge and Freezer Recycling Program	304	refrigerators/freezers	33,907	33,907	73,602	
Heating & Cooling Efficiency Program	712	projects	585,211	1,686,618	1,556,065	
Home Energy Audit	466	audits	264,394	321,978	211,003	
Home Energy Report Pilot Program	23,914	treatment size	194,812	194,812	3,281,780	
Multifamily Energy Savings Program	25	projects	205,131	205,131	655,953	
Oregon Residential Weatherization	5	audits	5,507	5,507		
Rebate Advantage	107	homes	147,483	355,115	284,559	
Residential New Construction Pilot Program	307	homes	400,912	926,958	777,369	
Shade Tree Project	2,093	trees	162,995	162,995	35,571	
Simple Steps, Smart Savings	7,377	appliances/ showerheads	90,484	133,101	241,215	
Weatherization Assistance for Qualified Customers	193	homes/non-profits	1,272,973	1,819,491	649,505	
Weatherization Solutions for Eligible Customers	141	homes	1,022,471	1,022,471	571,741	
Total			**$ 10,310,503**	**$13,634,216**	**43,651,278**	

Notes:
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.

Marketing

Idaho Power ran a multi-faceted advertising campaign in the spring (April and May) and fall (October and November) to raise and maintain awareness of the company's energy efficiency programs for residential customers and to demonstrate that saving energy does not have to be challenging (Figure 14). The campaign utilized radio, television, newspaper advertisements (ads), digital ads, Facebook ads, *News Briefs* sent to the media, the *Connections* newsletter, and Idaho Power's website to reach a variety of customer demographics. New in 2018, the company added print publications, YouTube video ads, Idaho Public TV, Google Ads, and digital ads at the Bogus Basin lodge. The company also continued the Smart-Saver Pledge sweepstakes (initiated in 2016) to engage and encourage customers to make an energy-saving behavior change.

Figure 14. Energy efficiency awareness campaign ad example

The company also continued to update individual program materials using the overall campaign imagery and theme to ensure a consistent look and feel among programs.

Below are Idaho Power's numerous marketing efforts to promote energy-saving tips and the company's energy efficiency programs, along with resulting data. Marketing tactics related to a specific sector or program are detailed in those respective sections later in this report.

Email

In May 2018, Idaho Power launched an effort to communicate via email with residential customers who had previously provided their addresses for a variety of reasons. An initial email was sent to 143,579 residential email addresses informing customers that Idaho Power will begin communicating with them via email and encouraging them to set their preferences to identify which categories of information they would like to receive emails about. The email categories included: company news, energy savings, green options, and ways to pay.

Idaho Power sent emails promoting the company's campgrounds, Energy-Saving Kits, paperless and auto pay, the Smart-Saver Pledge, energy-saving tips to prepare for winter, and a powering-the-holidays greeting. The emails had an average unique open rate of about 37 percent and an average unique click rate of about 4 percent. According to SendGrid's 2018 Global Email Benchmark Report, the aggregate open rate for energy and utilities is 31 percent and the aggregate click rate is 4.4 percent.

Figure 15. Idaho Power Smart-Saver Pledge email

Digital

Idaho Power placed ads on weatherbug.com and the WeatherBug app in the spring and in other online venues as part of the spring and fall campaign. The WeatherBug ads received 1,708,993 impressions (defined as the number of times an ad was displayed), 3,696 clicks, and a click-through rate (the percent of customers who clicked the ad and were directed to Idaho Power's Savings For Your Home web page) of 0.22 percent.

In the spring, web users were exposed to 1,785,483 display ads (image ads embedded into a website) based on their demographics, related to online articles they viewed or their use of a particular mobile web page or app. Users clicked on the ads 3,164 times, resulting in a click-through rate of 0.18 percent. In the fall, the display ads received 2,395,638 impressions and 2,393 clicks, resulting in a click-through rate of 0.10 percent.

Idaho Power began using Google search ads in 2018. When people search for terms related to energy efficiency, energy efficiency programs, and individual program measures, the company's ads appear and drive them to the appropriate energy efficiency web page. These ads received 9,643,409 impressions and

116,381 clicks throughout the year. The search terms with the highest engagement were Idaho Power, Idaho power company, idaho power, +Idaho +power rebates, smart thermostat, new +water +heater, idaho power boise, and tankless water heater.

Figure 16. Google search ad example

Idaho Power ran digital ads on radio station websites and on the television screens in the Bogus Basin Lodge during the 2017–2018 ski season. Idaho Power leveraged mobile geolocation services/technology to display digital ads to people in and around select movie theaters. These ads resulted in 243,736 impressions, 3,283 clicks and a click-through rate of 1.31 percent in the spring and 250,770 impressions, 962 clicks and a click-through rate of 0.38 percent in the fall. These digital ads ran in conjunction with on-screen and lobby ads playing within the theaters.

The company also ran ads on Pandora internet radio, YouTube, and Hulu. Those results can be found in the Radio and Television sections, respectively.

Television

Idaho Power used network television, Hulu, and YouTube advertising for the spring and fall campaign. The network television campaign focused on primetime and news programming that reaches the highest percentage of the target market: adults age 25 to 64.

During the spring campaign, an ad ran 1,959 times in the Boise, Pocatello, and Twin Falls media markets. The ads reached 71.5 percent of the Boise target audience, 60.1 percent of Twin Falls target audience, and 70.2 percent of the Pocatello target audience. The targeted customers saw the ad 9.9 times in Boise, 11.5 times in Twin Falls, and 8.3 times in Pocatello. Hulu ads delivered 419,083 completions, meaning that the ad was viewed in its entirety. YouTube video ads resulted in 534,620 impressions and 186,761 views.

During the fall campaign, the spot ran 1,609 times in the Boise, Pocatello, and Twin Falls media markets. The ads reached 68.6 percent of the Boise target audience, 41.3 percent of Twin Falls target audience, and 36.1 percent of the Pocatello target audience. The targeted customers saw the ad 5 times in Boise, 5.7 times in Twin Falls and 4.6 times in Pocatello. Hulu ads received 405,763 completions and YouTube video ads delivered 393,669 impressions and 146,206 views.

New in 2018, Idaho Power sponsored Idaho Public Television's *This Old House* and *Ask This Old House.* Fifty-two 15-second spots ran from April through September; the ads reached 7,634 households.

Radio

As part of its spring and fall campaign, Idaho Power ran 30-second radio spots on major commercial radio stations in the service area. To obtain optimum reach, the spots ran on a variety of station formats, including classic rock, news/talk, country, adult alternative, adult contemporary, and classic hits. The message was targeted toward adults age 25 to 64 throughout Idaho Power's service area.

Results of the spots are provided for the three major markets: Boise, Pocatello, and Twin Falls. During the spring campaign, Idaho Power ran 2,820 English radio spots. These spots reached 69.6 percent of the target audience in Boise, 81 percent in Pocatello, and 85.7 percent in Twin Falls. The target audience in Boise was exposed to the ad 7.6 times, 10.8 times in Pocatello, and 13.8 times in Twin Falls. During the fall campaign, the company ran 2,843 English radio spots. These spots reached 76.7 percent of the target audience in Boise, 47.4 percent of the target audience in Pocatello, and 90.4 percent of the target audience in Twin Falls. The target audience was exposed to the message eight times in Boise, 12.1 times in Pocatello, and 18.4 times in Twin Falls during the fall campaign.

Idaho Power also ran ads on Spanish-speaking radio stations and National Public Radio (NPR) stations in the service area. These ads ran 670 times in the spring and 732 times in the fall.

Idaho Power ran 30-second spots with accompanying visual banner ads on Pandora internet radio, which is accessed by mobile and web-based devices. In the spring, records show 1,049,382 impressions and 162 clicks to the Idaho Power residential energy efficiency web page. The fall ads yielded 1,055,222 impressions and 126 clicks. Other online radio ads resulted in 4,812 impressions and 164 clicks/plays.

Print

As part of the campaign, print advertising ran in the major daily and select weekly newspapers throughout the service area. The company also ran ads in the Idaho Shakespeare Festival program, Boise Hawks program, *Territory Magazine*, *Idaho Magazine*, Broadway in Boise program, and *Sun Valley Magazine*. The ads highlighted individual energy efficiency program options, such as how to get a home energy audit or the benefits of installing a DHP. The ads informed customers that Idaho Power can help them save energy and money regardless of whether they own or rent. The ads were scheduled for 2,168,892 impressions in 2018.

In 2018, Idaho Power developed a spiral-bound guide outlining each of the residential energy efficiency programs, tips, and resources. The guide was included in Welcome Kits mailed out to 30,500 new customers, provided to Weatherization Assistance customers, and handed out at a variety of events including the Building Owners and Managers Association (BOMA) Symposium, Idaho Remodeling & Design Show, Incredible Age Expo, FitOne℠ Expo, Smart Women Smart Money, Eastern Idaho Fair, Portneuf Environmental Fair, home shows in Pocatello, Twin Falls, Boise and Nampa, and more.

Social Media

Idaho Power's Facebook ads averaged 424,248 impressions and received 11,492 link clicks during the spring energy efficiency campaign. During the fall campaign, Facebook ads averaged 284,655 impressions and resulted in 1,384 link clicks, per available data. Due to a lapse in Facebook reporting, data for one November ad is not available, bringing the total impression and link click data down significantly. Fall campaign results may also be lower than previous months (2017 and 2018 campaigns) due to saturation of the market. In targeting the same service area with the same ads over multiple months, Facebook users may have started to scroll past the familiar ad rather than engage. Throughout the year, Idaho Power used Facebook posts and boosted posts for various programs.

Public Relations

Many of the company's PR activities focused on the residential sector. Energy-saving tips videos, TV segments, *News Briefs* content and *Connections* newsletter articles often aim to promote incentive programs and/or educate customers about behavioral or product changes they can make to save energy in their homes. Idaho Power also promoted the Smart-Saver Pledge, including outreach in *Connections*, *News Briefs*, and through regional TV segments.

See the Program Activity section and the Commercial and Industrial Sector Overview for more 2018 PR activities.

Empowered Community

In 2015, Idaho Power created the Empowered Community, an online community of residential customers, to measure customer perceptions on a variety of company-related topics, including energy efficiency. The community has almost 1,800 actively engaged members from across Idaho Power's service area. On average, Idaho Power sends one survey per month to active members. In 2018, Idaho Power included 11 energy efficiency messages with survey invitations to members resulting in over 8,700 touchpoints.

Email Test

In March and April, the company ran a pilot program with a subset of Empowered Community participants who agreed to receive and review a set of four emails and corresponding surveys within a month period. Participants received a text-only email introducing Idaho Power's email plans, an email promoting ESKs that included a combination of text and images, an image-only email promoting paperless billing, and an email with a link to a video about linemen saving a bee colony.

After each email, participants were asked if they received the email or if it ended up in a junk or spam inbox and about their overall impression of the email—if the length was appropriate, whether the call to action was clear, and their impression on the format (i.e., text, image, video or a combination thereof). Responses varied for each of the four emails tested, but overall, participants felt that the emails were clear and concise, included a good mix of images, text, and video, and left them with a neutral or positive impression.

Smart-Saver Pledge Sweepstakes

In 2018, Idaho Power continued the Smart-Saver Pledge sweepstakes to encourage customers in Idaho to make energy-saving changes. The sweepstakes ran from October 1 through November 20. Customers were asked to commit to making an energy-saving change for 21 days, choosing one of the following actions: change the porch light to an LED or add a timer, use a programmable pressure cooker once a week instead of the oven or stove, hang-dry clothes after washing, unplug the cell phone charger when not in use, or use kitchen and bath exhaust fans only when needed. In return, pledge participants were entered to win an ENERGY STAR® electric appliance.

Idaho Power promoted the pledge primarily with a bill insert and email. The bill inserts (Figure 17) went to 318,326 customers and included a sign-up form on the back for customers to mail in. The email was sent to approximately 147,000 customers and included a link to the online sign-up form. The pledge was also promoted through Facebook and Twitter posts. Additional promotion included *News Briefs*, the October issue of *Connections*, and a television news segment on KTVB where customers were directed to sign up on the Smart-Saver Pledge web page.

Figure 17. Smart-Saver Pledge bill insert

Idaho Power received 4,486 pledges throughout the pledge period and a few additional pledges after the pledge ended. In 2017, the company received fewer than 1,000 pledges. In addition to the greatly increased number of participants, the company received positive feedback from customers about the pledge and their energy habits. One customer stated, “Good for Idaho Power in trying to help people use less energy.” The company believes the participants were highly engaged and that the results were generally positive.

Customers were asked to complete a follow-up survey as part of the pledge. In return, participants were entered to win a $100 Visa gift card. The company received 2,302 responses to the follow-up survey in 2018 (about 51 percent of pledge participants). In 2017, the survey response rate was 42 percent. Highlights include the following:

- Over 94 percent of respondents fulfilled all 21 days of their pledge.
- Of the respondents who answered the question regarding whether they would continue their energy-saving changes, all but six planned to continue with the energy-saving changes after the pledge ended.
- Just over 61 percent of respondents indicated they were “very likely” to seek out additional ways to save energy.
- After taking the pledge, over 97 percent of respondents were “somewhat likely” or “very likely” to participate in an Idaho Power energy efficiency program.

A copy of the full survey results can be found in *Supplement 2: Evaluation*.

Customer Satisfaction

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2018, 64 percent of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-six percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Fifty-three percent of Idaho Power residential customers surveyed indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 41 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program.

Based on surveys conducted in the last six months of 2017 and the first six months of 2018, Idaho Power ranked second out of 14 utilities included in the west region midsize segment of *the J.D. Power and Associates 2018 Electric Utility Residential Customer Satisfaction Study*. Fifty-two percent of the residential respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and on an overall basis, those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

See the individual programs for program-specific customer satisfaction survey results.

A/C Cool Credit

		2018	2017
Participation and Savings			
	Participants (homes)	26,182	28,214
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	29	29
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$433,659	$495,142
	Oregon Energy Efficiency Rider	$36,425	$39,493
	Idaho Power Funds	$374,285	$401,637
	Total Program Costs—All Sources	$844,369	$936,272
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Originating in 2003, A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers in Idaho and Oregon. Using communication hardware and software, Idaho Power cycles participants' central air conditioning (A/C) units or heat pumps off and on via a direct load control device installed on the A/C unit. This program enables Idaho Power to reduce system capacity needs during times when summer peak load is high.

Customers' A/C units are controlled using switches that communicate by powerline carrier (PLC). The switch is installed on each participating customer's A/C unit and allows Idaho Power to control the unit during a cycling event.

The cycling rate is the percentage of an hour that the A/C unit will be turned off by the switch. For instance, with a 55 percent cycling rate, the switch should be off for about 33 (nonconsecutive) minutes of each hour. Idaho Power tracks the communication levels to validate whether the signal reaches the switches. There are many reasons why Idaho Power's PLC cannot communicate with a switch. The switch may be disconnected, an A/C unit may not be powered on, the switch may be defective, or the participant's household wiring may prevent communication. Sometimes it is difficult for the company to detect why the switch is not communicating. At the end of the season, Idaho Power evaluates event reductions using methodologies consistent with those established in prior third-party evaluations.

These are the program event guidelines:

- June 15 through August 15 (excluding weekends and July 4)
- Up to four hours per day

- A maximum of 60 hours per season
- At least three events per season

Program Activities

In 2018, about 26,000 customers participated in the program. Four cycling events occurred, and all were successfully deployed (Table 8). The cycling rate was 55 percent and the communication level exceeded 94 percent for each event. The incentive remained $15 per season, paid as a $5 bill credit on the July, August, and September bills.

Table 8. A/C Cool Credit demand response event details

Event Details	Monday, July 16	Wednesday, July 25	Tuesday, July 31	Monday, August 6
Event time	4–7 p.m.	4–7 p.m.	4–7 p.m.	4–7 p.m.
Average temperature	93°F	98°F	96°F	89°F
Maximum load reduction (MW)	29	27.3	27.3	10.4

For the third event, Idaho Power believes that the low results were partially due to low A/C use at the time of the event. In addition, the methodology used to determine the amount of reduction achieved for the event compared recent historical usage patterns to that of the event day. These results may be understated because the customers' use patterns from the prior ten days did not align well with the customer usage patterns on the day of the event, causing the savings to appear lower. For the fourth event, the lower reduction for this event corresponds to the cooler temperatures.

Marketing Activities

Per the settlement agreement reached in Idaho Case No. IPC-E-13-14 and Oregon Case No. UM 1653, Idaho Power did not actively market the A/C Cool Credit program in 2018. Idaho Power communicated with participants in an effort to retain them and with customers who moved into a home where a switch was present in an effort the utilize the installed equipment.

Before the cycling season began, Idaho Power sent current participants a postcard reminding them of the program specifics. Idaho Power also attempted to recruit customers who had moved into a home that already had a load control device installed and previous participants who changed residences to a location that may or may not have a load control device installed. The company used postcards, phone calls, direct-mail letters, and home visits (leaving door hangers for those not home) to recruit these customers. At the end of the summer, a thank-you postcard was sent to program participants.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for its demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2018.

The A/C Cool Credit program was dispatched for four events (totaling 12 event hours) and achieved a maximum demand reduction of 29.1 MW. The total expense for 2018 was $844,369 and would have remained the same if the program was fully used for 60 hours because there is no variable incentive paid for events beyond the three required events.

A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-effectiveness.*

Evaluations

Each year, Idaho Power internally evaluates the program reductions by determining the three days with the highest usage, out of the 10 days prior to an event, and comparing their usage to the event day usage. The baseline methodology performed as expected for three of the four events, but the third event on July 31 was lower than expected partially due to misalignment of the baseline days and the event day. The complete report is available in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

Idaho Power does not anticipate any program changes in 2019.

Per the terms of the above-mentioned settlement agreements, Idaho Power will not actively market the A/C Cool Credit program to solicit new participants but will accept them upon request, regardless of whether they previously participated. Attempts will continue to be made to recruit previous participants who have moved, as well as new customers moving into homes that already have a load control device installed.

Easy Savings: Low-Income Energy Efficiency Education

		2018	2017
Participation and Savings			
	Participants (coupons/kits)*	282	2,470
	Energy Savings (kWh)	29,610	280,049
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$147,936	$149,813
	Total Program Costs—All Sources	$147,936	$149,813
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$1.37	$0.064
	Total Resource Levelized Cost ($/kWh)	$1.37	$0.064
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

*In 2017–2018, the program transformed from energy-savings kits to electric heating system tune-up coupons.

Description

As a result of IPUC Case No. IPC-E-08-10 and Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for low-income customers and provide $125,000 to Community Action Partnership (CAP) agencies in the Idaho Power service area annually, on a prorated basis. These orders specified that Idaho Power provide educational information to Idaho customers who heat their homes with electricity.

From 2009 to 2017, using CAP agency personnel, the program distributed energy-saving kits and corresponding educational materials to participants of the Low Income Home Energy Assistance Program (LIHEAP) who heat their homes with electricity. In 2017, with input from a planning committee consisting of representatives from Community Action Partnership Association of Idaho (CAPAI), CAP Agencies, and the IPUC, Idaho Power discontinued kit distribution and offered a pilot incentive: a coupon for a free HVAC tune-up and one-on-one education with the goal of reducing the energy costs for LIHEAP participants. Contractors were reimbursed up to $300 per redeemed coupon.

Though this report discusses other program activities based on the calendar year, the following program information summarizes activities based on the federal fiscal year because CAP agencies use the fiscal LIHEAP program cycle.

Program Activities

By November 1, 2018, 659 coupons were distributed and 282 were redeemed by customers for heating system tune-ups. Of the $125,000 Idaho Power allotted to CAP Agencies for this pilot, $68,368 was paid to HVAC contractors for their service. Since this was a pilot, the unused funds were designated to provide additional coupons in 2018–2019 program year. Coupons expire at the end of the 2019 program year; no other conditions apply.

To participate, regional HVAC company owners were required to sign the Contractor Guidelines and acknowledge the two-fold goal of the pilot: customer education and equipment tune-up. During the customer visit, HVAC contractors performed the tune-up and taught residents how to change furnace filters. They also explained how regular maintenance improves overall performance and answered questions about the specific heating equipment and ways to save energy. The contractor left behind a customer satisfaction survey that could be mailed to CAPAI or completed online; respondents were entered into a drawing for a gift card.

The planning committee found that the $300-maximum per coupon was frequently inadequate to address all of the costs associated with minor tuning and/or repairing the heating systems. Customers were then referred to the CAP agencies to apply for additional assistance. These referrals caused an unintended strain on weatherization budgets. The Planning Committee also found that limiting eligibility to LIHEAP participants made it difficult to distribute the coupons because CAP agencies are busy assisting people during energy assistance season. As a result, the maximum per-coupon amount was increased to $600 in mid-2018.

Marketing Activities

The Easy Savings pilot is included under "Savings For Your Home" on the Idaho Power website in the "Income Qualified Customers" section.

Cost-Effectiveness

Idaho Power started tracking cost-effectiveness ratios for the program in 2015 when the company began claiming savings for the program. However, since the purpose of Easy Savings is primarily an educational and marketing program, the company determined that, like the Home Energy Audit program, the traditional cost-effectiveness tests should not apply. The cost-effectiveness goal of the program is to find trackable energy savings opportunities while maintaining the educational program mandate.

The Easy Savings HVAC coupon claimed 105 kWh of annual savings for each qualifying customer with air conditioning. The savings value is sourced to the 2016 energy efficiency potential study.

Customer Satisfaction

Information and comments gathered from the 2017–2018 customer survey show that most of the coupons were redeemed by customers during the month of September followed by March and January. October, December, and May had the lowest redemption rate.

Of the 141 surveys returned to CAPAI, 111 customers reported that the contractor demonstrated how to safely change filters. Ninety customers reported that the contractor recommended ways to save energy such as changing furnace filters, properly programming the thermostat, using a ceiling fan instead of air conditioning in the summer, and opening blinds during the day and closing them at night in the winter. One hundred eighteen respondents pledged to change furnace filters as recommended and 71 described other changes they made based on program recommendations.

One hundred seventeen participants reported they were very satisfied with the program and nine were somewhat satisfied.

2018–2019 Program and Marketing Strategies

The planning committee and participating regional HVAC contractors agreed to support Easy Savings a second year as Pilot #2 with these improvements:

1. Increase the maximum dollar amount available to contractors per customer visit to $600. This increase will allow the HVAC contractor to leave behind extra furnace filters and to make minor repairs to furnaces, air conditioners, and heat pumps while providing educational information.
2. Expand eligibility beyond LIHEAP recipients to all Idaho Power customers with electric heat systems who have participated in other income-specific programs in the past four years or to those on the waiting list for weatherization services. This will allow Easy Savings to reach more customers, provide interim assistance while customers wait for weatherization, and help extend the life of HVAC equipment previously installed with weatherization program funding.

Idaho Power revised the coupon and mailed them to CAP agencies in November 2018 for the 2018–2019 program year. Funding came from a combination of unused 2017–2018 and current-year 2018–2019 sources.

Educational Distributions

		2018	2017
Participation and Savings			
	Participants (kits/lightbulbs)	94,717	84,399
	Energy Savings (kWh)	19,333,668	21,187,261
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$3,307,782	$3,323,024
	Oregon Energy Efficiency Rider	$67,409	$141,860
	Idaho Power Funds	$0	$1,143
	Total Program Costs—All Sources	$3,375,192	$3,466,027
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.019	$0.016
	Total Resource Levelized Cost ($/kWh)	$0.019	$0.016
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.68	3.02
	Total Resource Benefit/Cost Ratio	4.51	6.33

*Program savings include Home Energy Report pilot program savings.

Description

Designated as a specific program in 2015, the Educational Distributions effort is administered through the Residential Energy Efficiency Education Initiative and seeks to use low-cost and no-cost channels to deliver energy efficiency items with energy savings directly to customers. As with the initiative, the goal for these distributions is to drive behavior change and create awareness of and demand for energy efficiency programs in Idaho Power's service area.

Idaho Power selects items for distribution if the initial analysis indicates the measure is either currently cost-effective or expected to be cost-effective. Typically, selected items have additional benefits beyond traditional energy savings, such as educating customers about energy efficiency, expediting the opportunity for customers to experience newer technology, or allowing Idaho Power to gather data or validate potential energy savings resulting from behavior change.

Idaho Power recognizes the need to educate and guide customers to promote behavior change and awareness and will plan program activities accordingly. Items may be distributed at events and presentations, through direct-mail, or during home visits conducted by customer representatives.

Energy-Saving Kits

Idaho Power knows that managing household energy use can be a challenge. To help make it easier for families, Idaho Power works with a kit vendor to offer two versions of its free ESKs: one for homes with electric water heaters and one for homes with alternate-source water heaters. Customers enroll at idahopower.com/save2day, by calling 800-465-6045, or by returning a postcard. A kit is sent directly to the customer's home.

Each ESK contains nine LED lightbulbs (six 800-lumen lightbulbs and three 480-lumen lightbulbs), a digital thermometer (to check refrigerator, freezer, and water temperatures), a shower timer, a water flow-rate test bag, an LED night light, and educational materials. In addition, the kit for homes with electric water heaters contains a high-efficiency showerhead with a thermostatic shower valve (TSV) and three faucet aerators.

Figure 18. Idaho Power's Energy-Saving Kit for homes with electric water heaters

Energy-Saving Kits as Giveaways

Idaho Power offers ESKs as giveaways, in limited quantities, at presentations and small events to garner additional interest in energy efficiency and to encourage immediate action and behavior change. In these circumstances, Idaho Power cannot confirm the source of water heating in the recipient's home or whether the recipient has already received a kit. Therefore, this version of ESK given away is the more basic version for homes with alternate-source water heaters; energy savings is garnered from lighting changes that are not dependent on the source of water heat.

Home Energy Report Pilot

In 2018, Idaho Power continued working with a third-party contractor, Aclara Technologies LLC (Aclara), to pilot the HER program. The objective of the HER pilot is to encourage customer engagement with electricity use in order to produce average annual behavioral savings of 1 to 3 percent. Secondary objectives are to maintain or increase customer satisfaction and obtain information to inform decisions around scalability, projected savings, best target audiences, and other possible program activities in the future.

The periodic reports provide customers with information about how their home's energy use compares with similar homes. The *Home Energy Reports* also give a breakdown of household energy use and offers suggestions to help customers change their energy-related behaviors. Aclara statistically estimates energy savings that result from customers receiving the report by comparing the energy use of the report recipients against the energy use of a similar control group.

LED Lightbulbs as Giveaways

Giving away LED lightbulbs is an effective way to connect Idaho Power with its customers and begin productive conversations around energy efficiency. Idaho Power field staff and energy efficiency program specialists seek opportunities to educate customers about LEDs, and to offer customers a free lightbulb to use immediately in their own homes.

Student Energy Efficiency Kit Program

The SEEK program provides fourth- to sixth-grade students in schools in Idaho Power's service area with quality, age-appropriate instruction regarding the wise use of electricity. Each child who participates receives an energy efficiency kit. The products in the kit are selected specifically to encourage energy savings at home and engage families in activities that support and reinforce the concepts taught at school.

Once a class enrolls in the program, teachers receive curriculum and supporting materials. Students receive classroom study materials, a workbook, and a take-home kit containing the following:

- Three LED lightbulbs
- A high-efficiency showerhead
- An LED nightlight
- A furnace filter alarm
- A digital thermometer for measuring water and refrigerator/freezer temperatures
- A water flow-rate test bag
- A shower timer

At the conclusion of the program, students and teachers return feedback to Idaho Power's vendor indicating how the program was received and which measures were installed. The vendor uses this feedback to provide a comprehensive program summary report showing program results and savings.

Unlike most residential programs offered by Idaho Power, SEEK results are reported on a school-year basis, not by calendar year.

Welcome Kits

Idaho Power uses a vendor to mail Welcome Kits to brand new customers between 35 and 45 days after electric service begins at their residence. Each kit contains four LED lightbulbs, a nightlight, a greeting card and a small flip-book containing energy-saving tips and information about Idaho Power's energy efficiency programs. The kits are intended to encourage first-time customers to adopt energy-efficient behaviors early in their new homes.

Program Activities

Energy-Saving Kits

In 2018, 44,691 kits were shipped to customer homes: 18,383 kits to homes with electric water heaters and 26,308 to homes with alternate-source water heaters. The kits for homes with electric water heaters continued to include an integrated high-efficiency showerhead with a TSV. TSVs reduce the behavioral waste caused by letting the water run unchecked while it warms up. With a TSV, water flow is automatically reduced to a trickle when the water reaches 95°F, sending a signal that the water is ready. Once in the shower, the customer simply pulls a toggle string to resume normal water flow.

Kits were distributed to all geographic regions within Idaho Power's service area: 43,849 to Idaho residences and 842 to Oregon homes.

Energy-Saving Kits as Giveaways

Field staff across Idaho Power's five regions distributed 700 giveaway kits at presentations, small events, and customer visits. The kits were particularly popular and appreciated by senior homeowners who had the opportunity to receive them at events sponsored by senior centers.

Home Energy Report Pilot

Idaho Power, in partnership with Aclara, completed its first full year of the HER pilot program on July 31, 2018.

The pilot was designed based on standard randomized control trial (RCT) methodology with treatment and control groups sized appropriately to detect statistically significant savings at or above 1.2 percent, and allowing for approximately 10 percent attrition over the pilot period. Customers identified to receive customized *Home Energy Reports* were divided into two distinct groups: the HER year-round group and the HER winter-heating group.

The primary difference between reports was the tips and advice for the winter-heating group focused on heating suggestions, whereas tips and suggestions for the year-round group contained a wide-range of topics including air-conditioning.

To finish year one of the pilot, the HER year-round group (approximately 19,100 customers) continued to receive bi-monthly reports in February, April and June, and the winter-heating group (approximately 7,900 customers) received reports in January and February.

The first-year results showed estimated energy savings for the treatment period to be statistically significant for the winter-heating group with participants using an average of 207 fewer kWh per home than their control group counterparts—a savings of 1.5 percent. For participants in the year-round group estimated savings for the period appeared to be statistically significant at about 150 kWh per home (between 1.3 and 1.7 percent below the control group), but only for those using more than 9,000 kWh per year. Within the year-round group, the participants using more than 12,000 kWh annually saw the greatest aggregate kWh savings, while the participants using between 9,000 and 12,000 kWh reduced their use by a higher overall percentage.

Idaho Power's customer solutions advisors responded to 411 HER pilot-related phone calls and inquiries during the first year. The participant-driven opt-out rate was low at .64 percent. In spite of this, the pilot experienced higher-than-expected attrition—15 percent (includes opt-outs, move-outs, etc.).

The customer satisfaction numbers, as collected through a small-sample telephone survey appeared to be favorable.

At the conclusion of the pilot's first year, the company decided to extend it for another year to gather additional information prior to making final decisions regarding scalability. The year-round group was optimized for savings using algorithms provided by the vendor. A new winter-heating group was added to test the effectiveness of a bi-monthly delivery schedule compared to year one's four-report schedule. Additionally, remaining first-year participants were divided into two report-delivery schedules: one receiving bi-monthly and one receiving quarterly reports.

LED Lightbulbs as Giveaways

In 2018, Idaho Power customer representatives delivered educational messages and lightbulbs to seniors in Pocatello, Boise, Nampa, Caldwell, and Payette, Idaho and Nyssa, Ontario, and Vale, Oregon. Participants at the Idaho Remodeling and Design Show, the Idaho Housing and Economic Development Conference, Earth Day events, and employee sustainability and safety fairs in Meridian, Caldwell, Nampa, and Pocatello received lightbulbs, too. Idaho Power was also present with an educational message and LED lightbulbs at Boise's Heart Walk, Meridian Business Days, American Falls Days, Chubbuck Days, and several school district-sponsored events across the service area. Lightbulbs were also distributed at the Smart Women, Smart Money Conference; The Incredible Age Expo; the FitOne℠ Expo; Idaho Power Shade Tree Project events; and at presentations for chambers of commerce, scout groups, and other community and civic organizations.

By the end of the year, Idaho Power employees had personally delivered a brief energy efficiency message and distributed 9,450 lightbulbs directly to customers.

Student Energy Efficiency Kit Program

During the 2017 to 2018 school year, Idaho Power community education representatives actively recruited fourth- to sixth-grade teachers to participate in SEEK. As a result, Resource Action Programs (RAP) delivered 9,439 kits to 332 classrooms in 122 schools within Idaho Power's service area. This resulted in 1,994 MWh of savings.

Welcome Kits

In January, Idaho Power partnered with a third-party vendor, Tinker Programs, to design, build, and distribute a smaller energy efficiency kit. Kits began shipping in February and almost 31,000 kits had been delivered by year-end. Feedback received to-date via social networks and email indicate the kits are well-received.

Figure 19. Example of a customer's social media response to Idaho Power's Welcome Kit

Marketing Activities

Energy-Saving Kits

Marketing efforts included three direct-mail campaigns from the kit vendor: one to about 50,000 customers in January, a second to about 48,000 customers in April, and a third to about 88,000 customers in September. Direct-mail efforts continue to yield enrollments of approximately 18 to 20 percent. Kits continued to be showcased at trade shows throughout the service area and 6,250 bookmarks highlighting instructions on how to order the kit were distributed at events and presentations. Numerous social media posts were used to bolster program awareness. The posts were shared by customers, increasing word of mouth marketing and helping to further promote activity (Figure 20).

Figure 20. Social media post from environmentally focused customer who received ESK

The kit was promoted to recipients of the *Home Energy Reports* in February/March (to those who hadn't already received a kit). It was also featured in two video segments: one Idaho Power representative appearance on KMVT in the Magic Valley (March) and in an Idaho Power produced video on home winter savings that ran on YouTube and Facebook.

The kit was prominently mentioned in the energy efficiency campaign TV and radio commercials that aired during March/April and October/November. Email marketing was a new option for Idaho Power in 2018, so in July and August, 88,000 customers who hadn't yet received a kit received an email promoting it. 29,379 customers opened the email; 5,936 of those who opened the email clicked through to the kit web page.

Energy-Saving Kits as Giveaways

Idaho Power field staff educated customers about energy efficiency by offering a free ESK with educational items and LED lightbulbs to get them started and on their way to saving energy.

Home Energy Report Pilot

Because the HER pilot program is based on the RCT methodology, the reports cannot be requested by customers, therefore the pilot is not marketed. The periodic reports were, however, used to cross-market Idaho Power's other energy efficiency programs.

LED Lightbulbs as Giveaways

In 2018, Idaho Power field staff and energy efficiency program specialists continued to seek opportunities to educate customers about LEDs and offer customers a free LED lightbulb to use immediately in their own homes.

Student Energy Efficiency Kit Program

At the onset of the 2017–2018 school year, Idaho Power community education representatives began using emails in conjunction with flyers to recruit new fourth- to sixth-grade teachers to participate in SEEK.

Welcome Kits

The Welcome Kits are not requested by customers; therefore, they are not marketed. Instead, each week Idaho Power sends a list of new customers to the vendor who fulfills the order.

Cost-Effectiveness

In situations where Idaho Power managed the energy efficiency education and distribution through existing channels, the cost-effectiveness calculations were based on the actual cost of the items. Conversely, if outside vendors were used to assist with distribution, the cost-effectiveness calculations included all vendor-related charges.

Energy-Saving Kits

The RTF provides mail-by-request deemed savings for LED lightbulbs, the integrated high-efficiency showerheads with a TSV, and faucet aerators. The RTF mail-by-request deemed savings values are discounted to reflect the potential that all of the kit items may not be installed. The LED lightbulbs each have a deemed savings value of 8.2 kWh per year. The integrated 1.75 gallon per minute (gpm) low-flow showerhead with TSV saves approximately 240 kWh annually. Because there were no deemed savings from the RTF for faucet aerators, Idaho Power looked to the Energy Trust of Oregon (ETO) which runs a similar kit program for residential customers in Oregon. However, the RTF met in July 2018 and deemed an energy savings value for faucet aerators. Those numbers will be used in 2019. Based on installation rates from participant surveys, ETO claimed 134 kWh for kitchen faucet aerators and 75 kWh for bathroom faucet aerators. Idaho Power reviewed the results of the three-month follow up survey sent to ESK participants and found that the installations rates were similar to ETO's.

The annual savings for an ESK for a home with an electric water heater is approximately 598 kWh. The annual savings for a kit for a home with a non-electric water heater is approximately 74 kWh.

Energy-Saving Kits as Giveaways

The giveaway kits contain the same measures as the non-electric ESK. For the nine LED lightbulbs included in the kit, Idaho Power used the RTF's giveaway deemed savings value of 8.2 kWh per bulb. The annual savings for each giveaway kit is approximately 74 kWh.

Home Energy Report Pilot

Before starting the pilot, the HER pilot program benefit cost-ratios were expected to be between 0.90 and 0.95 assuming 1.5 percent average savings across all treatment groups. The program is cost-effective looking at program year savings (July 2017-July 2018) and 2018 calendar year expenses even while only claiming a one-year savings life.

LED Lightbulbs as Giveaways

For the LED giveaways, Idaho Power used the giveaway deemed savings provided by the RTF. The RTF-deemed annual savings of 8.2 kWh includes assumptions regarding the installation rate, efficiency levels of the existing lightbulb, and the location of the installation.

Student Energy Efficiency Kit Program

The cost-effectiveness analysis for the SEEK offering was based on the savings reported by RAP during the 2017 to 2018 school year. RAP calculated the annual savings based on information collected from the participants' home surveys and the installation rate of the kit items. Questions on the survey included the number of individuals in each home, water-heater fuel type, flow rate of old showerheads, and the wattage of any replaced lightbulbs. The response rate for the survey was approximately 56 percent. The survey gathers information on the efficiency level of the existing measure within the home and which measure was installed. The energy savings will vary for each household based on the measures offered within the kit, the number of items installed, and the existing measure that was replaced. Based on the feedback received from the 2017 to 2018 school year, RAP projects that each kit saved approximately 211 kWh annually per household on average, and the program saved 1,993,950 kWh annually. A copy of the report is included in *Supplement 2: Evaluation*.

Welcome Kits

For the four LED lightbulbs included in the kit, Idaho Power used the RTF's giveaway deemed savings value of 8.2 kWh per bulb. The annual savings for each kit is approximately 33 kWh.

2019 Program and Marketing Strategies

Energy-Saving Kits

Idaho Power will continue offering ESKs in 2019. Promotional materials will be readily available for all customer-facing employees to use at their discretion. The company's social media posts, website, and other advertising will promote ESKs. Targeted direct-mail campaigns will also be employed.

Energy-Saving Kits as Giveaways

Idaho Power will continue to give away limited quantities of the basic kit for homes with alternate-source water heaters at presentations and small events to garner interest in energy efficiency.

Home Energy Report Pilot

Estimated savings and customer satisfaction will continue to be closely monitored. An expanded telephone survey will be conducted in the spring and a full review of customer satisfaction and estimated savings results for year two of the pilot will take place in July/August of 2019. Based on results, the company will finalize the design and decide whether to continue and/or scale the HER pilot.

LED Lightbulbs as Giveaways

Idaho Power plans to continue offering LED lightbulbs during customer visits and at a limited number of community events and presentations.

Student Energy Efficiency Kit Program

Plans for the 2018 to 2019 school year include updating the marketing flyer and marketing email for distribution to more remote schools and districts. The company will continue to leverage the positive relationships Idaho Power's community education representatives have within the schools to maintain program participation levels. It will also work with the vendor to pilot an alternative recruiting strategy in the Twin Falls area—with the vendor reaching out directly to eligible schools. Curriculum will be reviewed for continued relevance to state standards.

Welcome Kits

In 2019, Idaho Power will continue to offer Welcome Kits to first-time customers. The Welcome Kit will cross-promote other energy efficiency programs and encourage new customers to adopt energy-efficient behaviors upon moving into their new homes.

Other Educational Distributions

Idaho Power will continue to look for opportunities to engage customers with new technologies that stress the importance of energy-efficient behaviors at home. Idaho Power is also looking at alternative measures that may sustain the kit programs as lighting savings mature.

Energy Efficient Lighting

	2018	2017
Participation and Savings		
Participants (lightbulbs)	1,340,842	1,766,758
Energy Savings (kWh)	18,856,933	37,765,190
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$2,343,127	$4,787,259
Oregon Energy Efficiency Rider	$92,003	$84,223
Idaho Power Funds	$0	$1,406
Total Program Costs—All Sources	$2,435,130	$4,872,888
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.011	$0.012
Total Resource Levelized Cost ($/kWh)	$0.014	$0.026
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.67	4.09
Total Resource Benefit/Cost Ratio	6.64	4.63

Description

Idaho Power and other regional utilities participate in the Simple Steps, Smart Savings™ program which is managed by CLEAResult®. Idaho Power promotes Simple Steps, Smart Savings offerings to customers in two areas: this lighting program and the appliance promotion program (see the Simple Steps, Smart Savings section of this report).

Initiated in 2002, the Energy Efficient Lighting program follows a markdown model that provides incentives directly to manufacturers or retailers, with discounted prices passed on to the customer at the point of purchase. The benefits of this model are low administration costs, better availability of products to the customer, and the ability to provide an incentive for specific products. The program goal is to help Idaho Power's Idaho and Oregon residential customers afford more efficient lighting technology.

ENERGY STAR® lightbulbs are a more efficient alternative to standard incandescent and halogen incandescent lightbulbs. Lightbulbs come in a variety of wattages, colors, and styles, including lightbulbs for three-way lights and dimmable fixtures. ENERGY STAR lightbulbs use 70 to 90 percent less energy and last 10 to 25 times longer than traditional incandescent lightbulbs.

Idaho Power pays CLEAResult a fixed amount for each kWh of energy savings achieved. A portion of the funding Idaho Power provides is used to buy down the price of the product, and a portion is applied to program administration and marketing which varies and can be used for retailer promotions. Promotions include special product placement, additional discounts, and other retail merchandising tactics designed to increase sales.

In addition to managing the program's promotions, CLEAResult is responsible for contracting with retailers and manufacturers, providing marketing materials at the point of purchase, and supporting and training retailers.

Program Activities

In 2018, LED lightbulbs comprised 92 percent of the program's sales for the year, an increase from the 90 percent of lightbulb sales in 2017. LED fixtures comprised approximately 8 percent of program sales, which was an increase from the 5 percent of program sales in 2017.

In 2018, through the Bonneville Power Administration (BPA) Simple Steps, Smart Savings program, Idaho Power worked with 15 participating retailers, representing 99 individual store locations throughout its service area. Of those participating retailers, 48 percent were smaller grocery, drug, and hardware stores, and the remaining 52 percent were large retailers.

Marketing Activities

Several Simple Steps, Smart Savings promotions were conducted through CLEAResult at retail stores in 2018. These promotions generally involved special product placement and signs. CLEAResult staff continued to conduct monthly store visits in 2018 to check stock, point-of-purchase signs, and displays. Additionally, CLEAResult staffed 18 lighting events at Home Depot and Costco stores to educate customers about the importance of using LED lightbulbs and the Simple Steps promotion.

Additional activities in 2018 involved education and marketing. During events where Idaho Power sponsored a booth and distributed LED lightbulbs, customers were informed about the importance of using energy-efficient lighting, the quality of LED lightbulbs, and the special pricing available for the Simple Steps, Smart Savings qualified products.

The company continued to host an Energy Efficient Lighting program website to make available a *Change a Light* program brochure, designed to help customers select the right lightbulb for their needs and to discuss energy efficient lighting with customers at community events. Several *#TipTuesday* posts on social media throughout the year focused on energy efficient lighting. Idaho Power recommended using ENERGY STAR certified LED lightbulbs in its summer *Energy Efficiency Guide*, the January and February issues of *Connections*, the January *Home Energy Report* to the winter-heating group, and the March *Home Energy Report* to the year-round group participants who already received an ESK.

Cost-Effectiveness

In 2018, the Energy Efficient Lighting program provided 43 percent of all energy savings derived from residential energy efficiency customer programs and 12 percent of Idaho Power's direct program savings. Between 2017 and 2018, bulb sales declined nearly 24 percent while savings declined nearly 50 percent.

In January 2017, the RTF updated and revisited the assumptions for LEDs to account for market changes due to the federal standards compliance. Because LEDs are naturally becoming a larger share of the market, the RTF updated the current market baseline for lightbulbs. Due to the timing of the RTF's update, BPA and CLEAResult implemented the new savings in 2018 in the Simple Steps, Smart Savings promotion. The RTF LED workbook version 5.2 was the source of most lighting savings assumptions throughout Idaho Power's residential program offerings.

The annual saving for the most popular bulb type, the general-purpose lightbulb in the 250-1049 lumen range, decreased from 13 kWh to 10 kWh. This bulb type made up 53 percent of the total bulbs sold in the program and nearly 40 percent of the total savings. With the change in per-bulb savings and sales declining just over 15 percent, the total savings for this bulb type declined by nearly 3 million kWh between 2017 and 2018.

The second most popular bulb type is reflector lightbulb in the 250-1049 lumen range which is commonly used in recessed canned light fixtures. The RTF reduced the per bulb savings for this bulb type from 37 kWh to 24 kWh. These reflector bulbs made up just over 19 percent of the total lightbulbs sold in the program and nearly 30 percent of the total savings. In 2018, the 250-1049 lumen reflector lightbulb sales declined 50 percent compared to 2017. With the decline in both sales and deemed savings, the total savings for this bulb type declined over 13 million kWh between 2017 and 2018.

The RTF reviewed and approved new savings for LEDs in December 2017. Based on the timing of when BPA and CLEAResult adopt new savings from the RTF, these updates will be reflected in the 2019 program year. The annual savings for lightbulbs have continued to decline. The reflector lightbulbs in the 250-1049 lumen range will go from 24 kWh to 8 kWh. The RTF met in November 2018 to update the LED savings again. With the final phase of EISA going into effect in January 2020, Idaho Power is monitoring how utilities in the region plan to incorporate the latest RTF numbers beyond January 1, 2020.

The UCT and TRC ratios for the program is 4.67 and 6.64 respectively. While an impact evaluation was conducted for the program in 2018, a majority of the evaluations costs will be incurred in 2019. However, if the amount incurred in 2018 was removed from the program's cost-effectiveness, the UCT and TRC ratios would be 4.68 and 6.65 respectively.

For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

Evaluations

Idaho Power retained Tetra Tech MA to conduct an impact evaluation of the Energy Efficient Lighting program. Overall, the evaluation found that the Energy Efficient Lighting program calculations were accurate with little variation by individual LED lightbulb or fixture type. As shown in Table 9, realization rates for each RTF version used were both very close to 100 percent and became even more accurate when RTF version 5.2 was adopted. Much of this increase in accuracy occurred when Idaho Power discontinued rounding the unit savings to the nearest whole number after moving to RTF version 5.2 in October 2017.

Table 9. Savings and realization rate based on RTF version for Energy Efficient Lighting

RTF Applied to Savings	Ex-Ante kWh	Ex-Post kWh	Realization Rate
RTF version 4.2 Applied (10/2016–9/2017)	33,238,504	33,506,134	101%
RTF version 5.2 Applied (10/2017–9/2018)	4,526,238	4,526,469	100%
Program Year 2017	37,764,742	38,032,603	101%

Idaho Power will respond to any 2018 evaluation recommendations during the 2019 program year. The complete report can be found in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

Idaho Power will continue to participate in the Simple Steps, Smart Savings lighting program in 2019 by contracting with CLEAResult, who was awarded the annual BPA implementation contract. New savings will be calculated using the new RTF workbook, version 6.1.

Idaho Power will monitor the number of participating retailers and geographic spread of these retailers and develop online promotions that allow customers to access promotional pricing regardless of location. The company will continue to monitor how regional stakeholders respond to the *Energy Independence and Security Act* (EISA) lighting standards that will go into effect on January 1, 2020.

CLEAResult will manage marketing at retailers, including point-of-purchase signs, special product placement, and displays. Idaho Power program specialist and customer representatives will continue to staff educational events to promote the importance of using energy-efficient lighting.

Energy House Calls

		2018	2017
Participation and Savings			
	Participants (homes)	280	335
	Energy Savings (kWh)	374,484	428,819
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$146,712	$170,691
	Oregon Energy Efficiency Rider	$14,065	$12,008
	Idaho Power Funds	$0	$336
	Total Program Costs—All Sources	$160,777	$183,035
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.032	$0.032
	Total Resource Levelized Cost ($/kWh)	$0.032	$0.032
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.37	1.26
	Total Resource Benefit/Cost Ratio	1.74	1.65

Description

Initiated in 2002, the Energy House Calls program gives homeowners of electrically heated manufactured homes an opportunity to reduce electricity use by improving the home's efficiency. Specifically, this program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon who use an electric furnace or heat pump. Participation is limited to one service call per residence for the lifetime of the program.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set and maintained by the BPA; installing up to eight LED lightbulbs; testing the temperature set on the water heater; installing water heater pipe covers when applicable; installing up to two low-flow showerheads, one bathroom faucet aerator, and one kitchen faucet aerator; and leaving two replacement furnace filters with installation instructions and energy efficiency educational materials appropriate for manufactured-home occupants.

Idaho Power provides contractor contact information on its website and marketing materials. The customer schedules an appointment directly with one of the certified contractors in their region. The contractor verifies the customer's initial eligibility by testing the home to determine if it qualifies for duct-sealing. Additionally, contractors have been instructed to install LED lightbulbs only in high-use areas of the home, to replace only incandescent lightbulbs, and to install bathroom aerators and showerheads only if the upgrade can be performed without causing damage to a customer's existing fixtures.

The actual energy savings and benefits realized by each customer depend on the measures installed and the repairs and/or adjustments made. Although participation in the program is free, a typical cost for a similar service call would be $400 to $600, depending on the complexity of the repair and the specific measures installed.

Program Activities

In 2018, 280 homes received products and/or services through this program, resulting in 374,484 kWh savings (Figure 21). The decrease in participation is likely due to the program nearing saturation. The program was introduced in 2002 and is one of Idaho Power's longest-running energy efficiency programs. Since participation is limited to once per home for the life of the program and is only available to electrically heated manufactured homes, there are a limited number of available homes that meet the qualifications to participate.

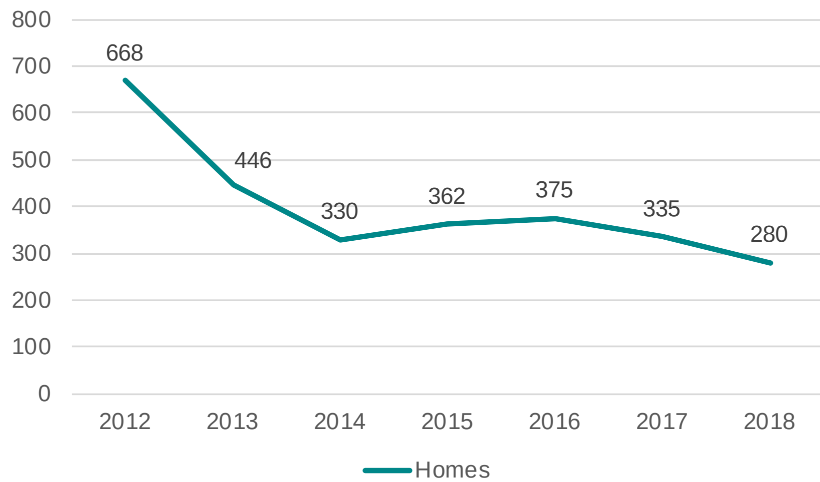


Figure 21. Participation in the Energy House Calls program, 2012–2018

Of the total participating homes, 39 percent were located in the Canyon–West Region, 23 percent were located in the Capital Region, and 38 percent were located in the South–East Region.

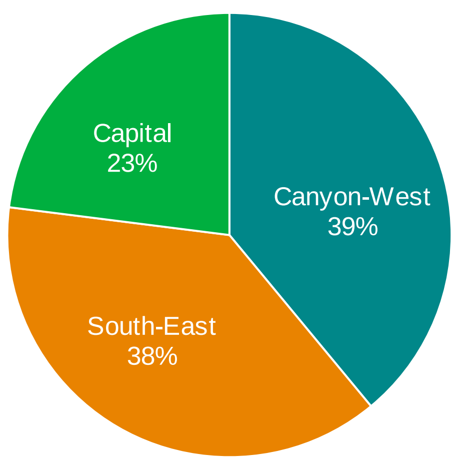


Figure 22. Energy House Calls participation by region

Duct-Sealing

Each year, a number of customers who apply for the Energy House Calls program cannot be served because their ducts do not require duct-sealing or cannot be sealed, for various reasons. These jobs are billed as a test-only job. On some homes, it is too difficult to seal the ducts, or the initial duct blaster test identifies the depressurization to be less than 150 cubic feet (ft) per minute (cfm) and duct-sealing is not needed. Additionally, if after sealing the duct work the contractor is unable to reduce leakage by 50 percent, the contractor will bill the job as a test-only job. Prior to 2015, these test-only jobs were not reported in the overall number of jobs completed for that year, because there was no kWh savings to report. Because Idaho Power now offers direct-install measures in addition to the duct-sealing component, all homes are reported. While some homes may not have been duct-sealed, all would have had some of the direct-install measures included, which would allow Idaho Power to report kWh savings for those homes. Of the 280 homes that participated in 2018, 38 homes were serviced as test-only.

If a home had a blower door and duct blaster test completed, and the contractor determined that only duct-sealing is necessary, it will be billed as a test and seal. For a multisection home with an x-over duct system (one that transfers heated or cooled air from one side to the other) that needs replaced in addition to the duct-sealing, it will be charged as an x-over. When a home requires the existing belly-return system to be decommissioned and have a new return installed along with the duct-sealing, it will be billed as a complex system. A complex system that also requires the installation of a new x-over and duct-sealing will be billed as a complex system and x-over job.

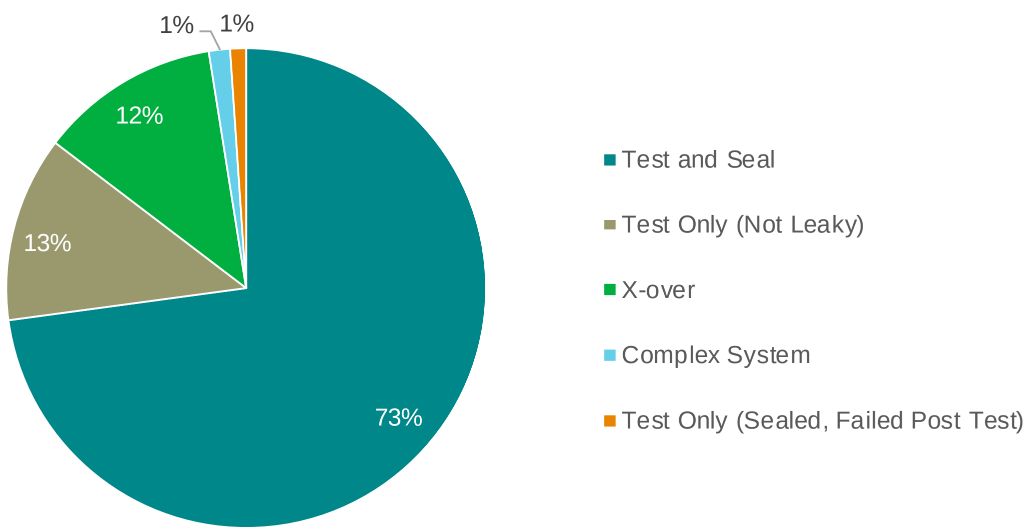


Figure 23. Energy House Calls participation by job type

Direct-Install Measures

In 2018, contractors installed 2,357 LED lightbulbs, 116 showerheads, 151 bathroom aerators, and 150 kitchen aerators. Contractors noted that they've seen a decrease in direct-install measures, as customers have commented that they have already installed the provided products after receiving their free ESKs from Idaho Power. In 2018, 31.4 percent of the Energy House Calls participants have received an ESK, which is up from the 20.2 percent of participants who had received the ESK in 2017.

Marketing Activities

Idaho Power sent two bill inserts to all residential customers in Idaho and Oregon in 2018. The March bill insert was shared with the Rebate Advantage program and sent to 345,506 customers, and the December bill insert was sent to 327,964 customers. The company sent postcards in February and July to residents of electrically heated manufactured homes who had not yet participated in the program. Written in English and Spanish, 9,495 postcards were delivered in February and 9,435 in July.

A Facebook ad ran in June and reached 43,728 people, resulting in 491 website clicks. Idaho Power also ran digital ads in English and Spanish in December. The English ads received 680,274 impressions and 5,242 clicks. The Spanish ads garnered 176,433 impressions and 1,407 clicks. In addition, Idaho Power customer representatives and customer service representatives knowledgeable about the program continued to promote it to qualified customers.

Cost-Effectiveness

In 2018, Idaho Power used the same RTF savings for duct-sealing in manufactured homes as were used in 2017. Savings and a cost-effectiveness analysis for the direct-install measures, including low-flow showerheads and LED lightbulbs, were completed using deemed savings from the RTF. Because there were no deemed savings from the RTF, Idaho Power used faucet aerators savings from the 2016 potential study for the 2018 program year. However, the RTF met in July 2018 and deemed an energy savings value for faucet aerators. Those numbers will be used in 2019.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

2019 Program and Marketing Strategies

Idaho Power will continue to provide free duct-sealing and selected direct-install efficiency measures for all-electric manufactured/mobile homes in its service area. As always, the company will continue to explore additional cost-effective measures to add to the program.

Idaho Power will include program promotional materials in its bills, send direct-mail postcards, and use social media and other proven marketing strategies. Contractors and customer representatives will also distribute program literature at appropriate events and presentations. Idaho Power will continue to provide Energy House Calls program postcards to CAP agencies for distribution to customers who need assistance but do not qualify to receive weatherization assistance through these agencies.

Heating & Cooling Efficiency Program

		2018	2017
Participation and Savings			
	Participants (projects)	712	654
	Energy Savings (kWh)	1,556,065	1,138,744
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$565,780	$575,404
	Oregon Energy Efficiency Rider	$19,431	$18,920
	Idaho Power Funds	$0	$2,874
	Total Program Costs—All Sources	$585,211	$597,198
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.029	$0.041
	Total Resource Levelized Cost ($/kWh)	$0.085	$0.099
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.65	1.48
	Total Resource Benefit/Cost Ratio	0.83	0.85

Description

The H&CE Program provides incentives to residential customers in Idaho Power's Idaho and Oregon service area for the purchase and proper installation of qualified heating and cooling equipment and services.

Initiated in 2007, the objective of the program is to provide customers with energy-efficient options for electric space heating and cooling in an effort to save energy. Incentives are paid to participating residential customers for all measures; incentives are paid to installing contractors for three measures. To participate in this program, a contractor must first complete the required training regarding program guidelines and technical information on HVAC equipment. Idaho Power requires licensed contractors to perform the installation services related to all of these measures, except evaporative coolers and HPWH.

The H&CE Program's list of measures and incentives includes the following:

- The customer incentive for replacing an existing ducted air-source heat pump with a new ducted air-source heat pump is $250 for a minimum efficiency 8.5 Heating Seasonal Performance Factor (HSPF).
- The customer incentive for replacing an existing oil or propane heating system with a new ducted air-source heat pump is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- The customer incentive for replacing an existing electric forced-air or zonal electric heating system with a new ducted air-source heat pump is $800 for a minimum efficiency 8.5 HSPF.

- The incentive for customers or builders of new construction installing a ducted air-source heat pump in a new home is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- The customer incentive for replacing an existing ducted air-source heat pump with a new ducted open-loop water-source heat pump is $500 for a minimum efficiency 3.5 coefficient of performance (COP).
- The customer incentive for replacing an existing electric forced-air or zonal electric, oil, or propane heating system with a new ducted open-loop water-source heat pump is $1,000 for a minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.
- The incentive for customers or builders of new construction installing a ducted open-loop water-source heat pump in a new home is $1,000 for a minimum efficiency 3.5 COP. Participating homes must be located in areas where natural gas is unavailable.
- The customer incentive for displacing a zonal electric heating system with a new ductless air-source heat pump is $750.
- The customer incentive for duct-sealing services performed in an existing home with an electric forced-air heating system or a heat pump is $350.
- The customer incentive for a whole-house fan (WHF) installed in an existing home with central A/C, zonal cooling, or a heat pump is $200.
- The customer incentive for replacing a Permanent Split Capacitor (PSC) air handler motor with an Electronically Commutated Motor (ECM) in an existing home with oil or propane or natural gas forced-air heat, electric forced-air heat, or a heat pump is $50.
- The customer incentive for installing an evaporative cooler is $150.
- The customer incentive for a smart thermostat installed in an existing home with an electric forced-air furnace or a heat pump is $75.
- The customer incentive for installing a HPWH is $300.

Honeywell, Inc., a third-party contractor, reviews and submits incentive applications and submits requests for payment using a program database portal developed by Idaho Power that is secure yet accessible. Honeywell also provides on-site technical and program support to customers and contractors and performs on-site verifications (OSV).

Program Activities

Idaho Power began offering a cash incentive to customers who installed a HPWH on January 1, 2018. During the development stage of this measure, the company provided updates and requested input from EEAG at quarterly meetings. EEAG's feedback regarding the measure was positive overall.

The 2018 H&CE Program paid incentives are listed in Table 10.

Table 10. H&CE Program incentives in 2018

Incentive Measure	2018 Project Quantity
Ducted Air-Source Heat Pump	172
Ducted Open-Loop Water-Source Heat Pump	14
Ductless Heat Pump	211
Evaporative Cooler	16
Whole-House Fan	41
Electronically Commutated Motor	58
Duct-Sealing	15
Smart Thermostat	155
Heat Pump Water Heater	27

Honeywell performed random OSVs on 10 percent of the completed installations. These OSVs confirmed the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable.

Supporting, retaining, and expanding Idaho Power's contractor network remained a key growth strategy for the program. In 2018, the company held meetings with many prospective contractors to support this strategy; 16 contractors were added to the program. Idaho Power also provided 22 one-on-one training sessions with contractors in 2018.

Idaho Power made changes to the program based on recommendations from a process and impact evaluation conducted in 2017 by DNV GL. (A copy of the final report can be found in the *Demand-Side Management 2017 Annual Report, Supplement 2: Evaluation*.) A risk and mitigation register was added to the Program Handbook. A revision history was also added along with a list of program measures with their incentive amounts. Though the evaluator suggested adding a logic model, organizational chart, and process flow to the Program Handbook, Idaho Power determined a logic model and organization chart would not provide value to the Program Handbook; therefore, they were not added. A process flow already exists in the Program Handbook.

Additionally, on the submittal forms, fields labeled "homeowner house type" and "existing primary cooling system type" were added to the air source and open loop water-source heat pump installation worksheet forms. Though the evaluator suggested adding the word "primary" to the existing field labeled "Previous/Existing System" on the Incentive Application form, Idaho Power determined that this change would not add value, therefore it was not included.

As recommended, Idaho Power will continue monitoring market transformation related to this program's available measures with input from the RTF and NEEA.

Marketing Activities

In response to the DNV GL evaluation and as part of the company's overall website redesign in early 2018, Idaho Power included a variety of visual content on the program web page. The company also adopted the recommendation to include photos of people displaying positive emotions in its marketing collateral and corrected strange font characters on the web page as recommended by the evaluator.

Idaho Power used multiple marketing methods for its H&CE Program. The company mailed a bill insert to 343,976 residential customers in April and 331,632 residential customers in September. Information about the program was included in the January and July issues of *Home Energy Reports*. Idaho Power sent a direct-mail postcard highlighting each incentive and customized for the season to 34,639 customers in March and 37,790 customers in August. A postcard highlighting whole house fans was sent to 2,990 customers with central air conditioning in May in an effort to better target an individual incentive to a group of customers that were not receiving other H&CE Program postcards.

Figure 24. Whole-house fan advertising postcard

Several social media and *#TipTuesday* posts throughout 2018 focused on heating- and cooling-related tips. Digital ads ran in February, July and August to promote the H&CE Program. The February ads used a new method called geofencing, which delivered ads to users that visit locations that serve targeted customers such as recycling centers and natural food grocery stores. The February digital ads received 1,456,373 impressions and 2,201 clicks. The July and August ads received 8,205,285 impressions and 7,026 clicks. Both ads resulted in a significant increase in web page visits.

The company also ran Facebook ads in February and July promoting the program during extreme temperatures. The February ad reached 126,429 people and resulted in 346,791 impressions and 2,815 clicks to the H&CE web page. The July ad reached 96,192 people and earned 311,908 impressions and 2,609 web page clicks.

Idaho Power created individual flyers for each program measure to use with interested customers and contractors and at events. Additionally, smart thermostats were mentioned in the winter *Energy Efficiency Guide*.

In 2018, Idaho Power continued using an ad promoting DHP as part of the company's overall residential energy efficiency campaign. The DHP ad was featured in a variety of mass-media locations. Full details on where the campaign ads appeared can be found in the Residential Sector Overview.

With the launch of the HPWH incentive in early 2018, Idaho Power conducted a variety of promotions specific to that incentive. The company announced the incentive to employees in *News Scans* and the media in *News Briefs* in early January. In February, the company developed a sticker for customers to place on their existing water heater as a reminder to consider a HPWH when it's time for a replacement. The sticker is included in all ESKs sent to customers with electric water heaters. That same month, HPWHs were promoted during monthly TV segments on KTVB, KPVI, and KMVT. A Facebook ad promoting the incentive ran in March and resulted in 2,279 link clicks, 85,815 people reached and 212,788 impressions. The first customer who received a HPWH incentive was featured on the cover of the April issue of *Connections*. Additionally, letters were mailed to 267 wholesalers and plumbing installers in June and to retailers with copies of the HPWH-specific flyer in July. A pull-up banner displaying a full size HPWH and incentive information was created in February for use at trade shows and events throughout the year. Several social media posts also focused on HPWHs and the incentive.

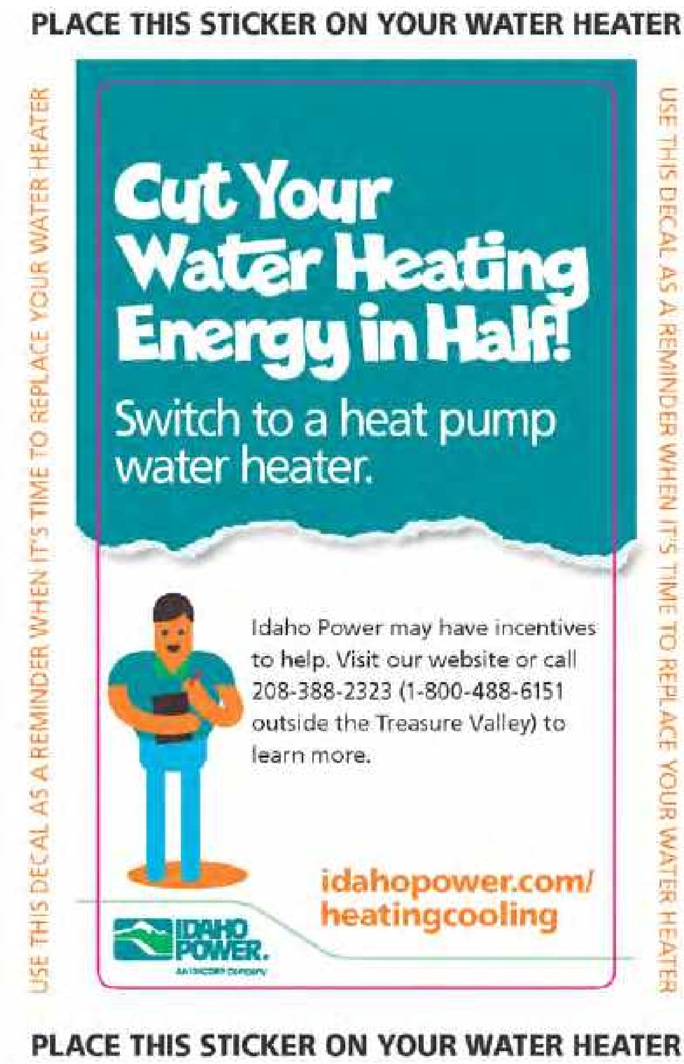


Figure 25. HPWH sticker

Cost-Effectiveness

The H&CE Program has a utility cost test of 1.65 and total resource cost test of 0.83. While the utility cost test improved in 2018 and the total resource test stayed the same when compared to 2017, using the

2017 program load shape, the total resource cost test increased to just over 1.0. Calibrations to end-use load shapes created for the 2016 energy efficiency potential study offset cost-effectiveness gains from cost control efforts in 2018.

Throughout 2017 and into 2018, Idaho Power worked toward improving program cost-effectiveness. These tactics included: 1) reassigning non-program labor, 2) reducing marketing spend while optimizing campaigns, 3) reducing contractor incentives from $150 to $50, 4) and adding HPWHs to the program. These efforts were successful in keeping cost-effectiveness ratios from falling in 2018 over 2017 levels.

DHPs continue to drag down cost-effectiveness of the program. The TRC is 0.96 when removing DHPs from cost-effectiveness calculations while the TRC of ductless systems is 0.69. Market transformation efforts, specifically the market transformation work provided by NEEA, in the region have failed to drive prices down along with lower net savings in colder climates are the two primary problems plaguing DHP cost-effectiveness.

Program savings were positively impacted for ECMs. Savings increased from 515 annual kWh to an average of 2,098 per installation by estimating in-situ savings that are a function of actual customer fan motor usage data collected on the incentive application forms. Customer specific behavior-based savings estimation was recommended in the 2017 program evaluation.

The savings assumptions for most measures including air source heat pumps, open loop water source heat pump, DHPs, and duct sealing remain unchanged from 2017. As a result, DHPs and open-loop water source heat pumps remain not cost-effective. These measures have cost-effectiveness exceptions with the OPUC under UM 1710. In addition to these measures, smart thermostats also remain not cost-effective. Idaho Power received a cost-effectiveness exception with the OPUC under Advice No. 17-09 due to the measure being a pilot. Other measures that are shown to not be cost-effective are heat pumps water heaters and duct-sealing. However, these measures would be cost-effective if administration costs were not included in the cost-effectiveness analysis.

An impact and process evaluation was conducted for the program in 2017 and a majority of the evaluation costs were incurred in 2017. However, a small amount of the evaluation costs carried over into 2018. If the amount incurred in 2018 was removed from the program's cost-effectiveness, the UCT and TRC ratios would be 1.66 and 0.84 respectively.

For detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness.*

For 2018 savings calculations, Idaho Power updated climate references in the program's databases to match the current values posted on the RTF website based on the evaluator's recommendation.

The evaluator recommended the continued use of the latest RTF data and to note other sources of energy-savings data when used by the program. The company is in alignment with this. The evaluator also recommended that Idaho Power add a variable to Idaho Power's data tracking system to note when its data for a particular incentive application is changed and no longer matches the information on the incentive application forms received. As an alternative, Idaho Power decided to edit the forms to match any changes made to the data, eliminating the need for a variable in the database.

For detailed information about the program evaluation, see the *Demand-Side Management 2017 Annual Report, Supplement 2: Evaluation.*

2019 Program and Marketing Strategies

Idaho Power will continue to provide program training to existing and prospective contractors to assist them in meeting program requirements and furthering their product knowledge. Sessions will be held at contractor businesses. Training sessions remain an important part of the program because they create opportunities to invite additional contractors into the program. The sessions also provide refresher training for contractors already participating in the program and help them increase their customers' participation while improving the contractors' work quality.

Developing the existing network of contractors participating remains a key strategy for the program. The performance of the program is substantially dependent on the contractors' abilities to promote and leverage the measures offered. Idaho Power's primary goal in 2019 is to develop contractors currently in the program while adding new contractors. To meet this objective, the program specialist will arrange frequent individual meetings to discuss the program with contractors in 2019.

The 2019 marketing strategy will include bill inserts, direct-mail, social media, digital and search advertising, and email marketing to promote individual measures and the program as a whole. As recommended by the evaluator, Idaho Power will explore options for updating the marketing materials to use visuals other than the house graphic, research ways to track the effectiveness of marketing campaigns, and consider adding video content to the program web page.

Home Energy Audit

		2018	2017
Participation and Savings			
	Participants (homes)	466	520
	Energy Savings (kWh)	211,003	175,010
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$264,394	$281,125
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$0	$1,684
	Total Program Costs—All Sources	$264,394	$282,809
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.113	$0.146
	Total Resource Levelized Cost ($/kWh)	$0.137	$0.182
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

The current Home Energy Audit program is based on the insights gained from the Boise City Home Audit project conducted in 2011 and 2012, as described in the *Demand-Side Management 2012 Annual Report*. In 2014, the audit project became Idaho Power's Home Energy Audit program.

A certified, third-party home performance specialist conducts an in-home energy audit to identify areas of concern, and to provide specific recommendations to improve the efficiency, comfort, and health of the home. The audit includes a visual inspection of the crawlspace and attic, a health and safety inspection, and a blower door test to identify and locate air leaks. The home performance specialist collects information on types and quantities of appliances and lighting in each home, then determines which available measures are appropriate for the home. Homeowners and/or landlords approve all direct-install measures prior to installation, which could include the following:

- Up to 20 LED lightbulbs
- One high-efficiency showerhead
- Pipe insulation from the water heater to the home wall (approximately 3 ft)
- Tier 2 Advanced Power Strip

The home performance specialist collects energy-use data and records the quantity of measures installed during the audit using specialized software. After the audit, the software creates a report of findings and recommendations for the customer.

To qualify for the Home Energy Audit program, a participant must live in Idaho and be the Idaho Power customer of record for the home. Renters must have prior written permission from the landlord. Single-family site-built homes, duplexes, triplexes, and fourplexes qualify, though multi-family homes must have discrete heating units and meters for each unit. Manufactured homes, new construction, or buildings with more than four units do not qualify.

Interested customers fill out an application online. If they do not have access to a computer, or prefer talking directly to a person, Idaho Power accepts applications over the phone. Participants are assigned a home performance specialist based on geographical location to save travel time and expense.

Participating customers pay $99 (all-electric homes) or $149 (other homes: gas, propane, or other fuel sources) for the audit and installation of measures, with the remaining cost covered by the Home Energy Audit program. The difference in cost covers the additional testing that is necessary for homes that are not all-electric. These types of energy audits normally cost $300 or more, not including the select energy-saving measures, materials, and labor. The retail cost of the materials installed in each home averages $145.

Program Activities

Because the CAKE Systems audit software was discontinued at the end of 2017, in 2018 the home performance specialists used an audit tool created by Idaho Power when the program was the Boise City Home Audit project. To find a permanent software solution, various software vendors were invited to submit bids through a competitive RFP. A cross-functional team selected the software (SnuggHome) that would best fit the needs of this program, including enhancements to meet strict cyber security requirements. Testing and training has been completed, and home energy audits completed in 2019 will use the new software.

In the first quarter, Idaho Power added a new direct-install audio/visual smart strip to the list of available measures. The smart strip is an eight-outlet power strip that provides constant power to two of the outlets, and on-demand power to the other six. The constant power is for electronics, such as a cable box or recorder, while the on-demand power is used for peripherals, such as a TV, an amplifier, a DVD player, speakers, etc. The smart strip shuts off the on-demand power when a predetermined amount of time has passed since the device was last used.

Three home performance specialist companies served the program in 2018 and completed 466 energy audits. House size ranged from 625 square ft (ft^2) to 9092 ft^2, with 2383 ft^2 being the average-sized home. Houses were built from 1883 to 2018, with the average age of home being 35 years old.

Figure 26 depicts the program's reach across Idaho Power's service area, and Figure 27 depicts the space and water heating fuel types. Figure 28 indicates the total quantity of direct-install measures.

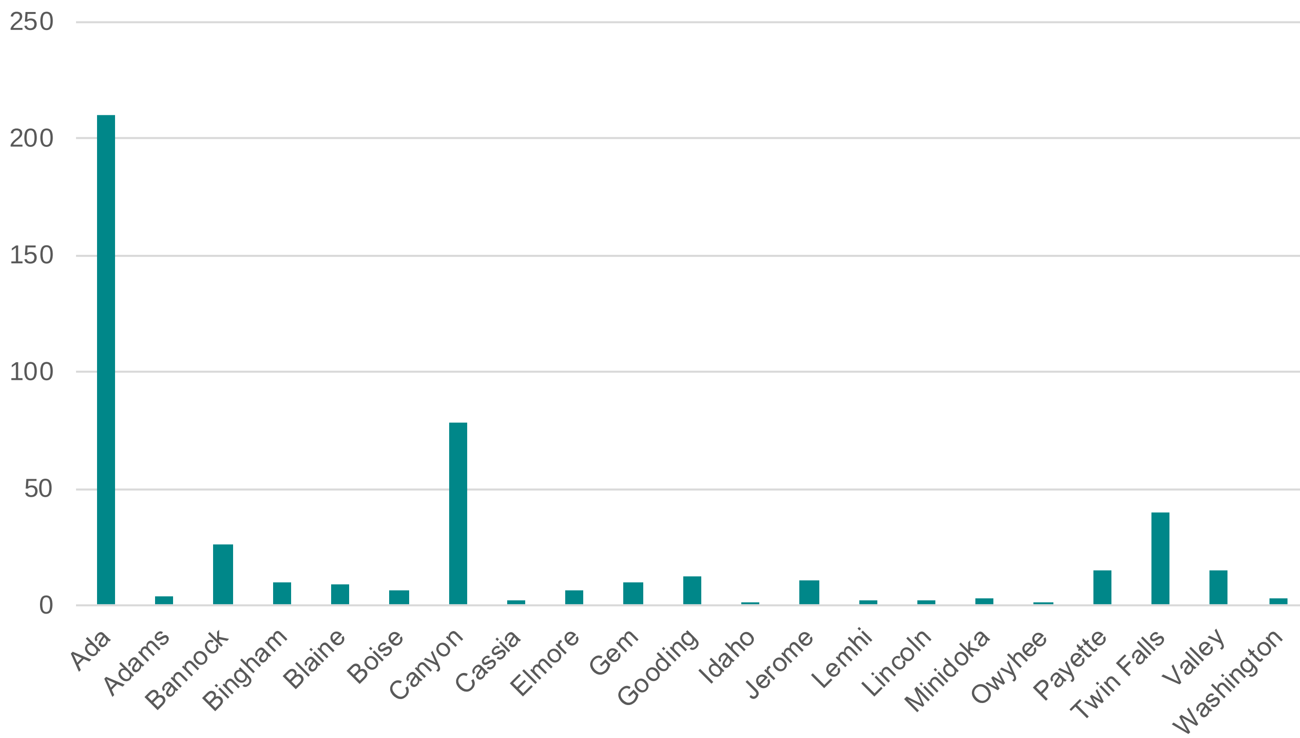


Figure 26. Home Energy Audit summary of participating homes, by county

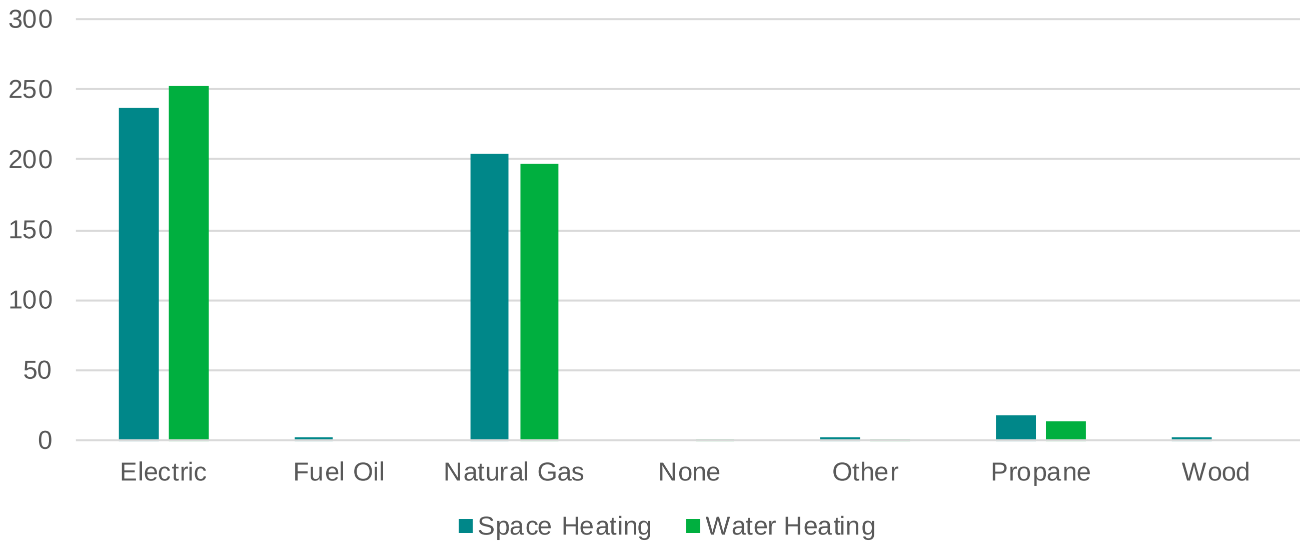


Figure 27. Home Energy Audit summary of space and water heating fuel types

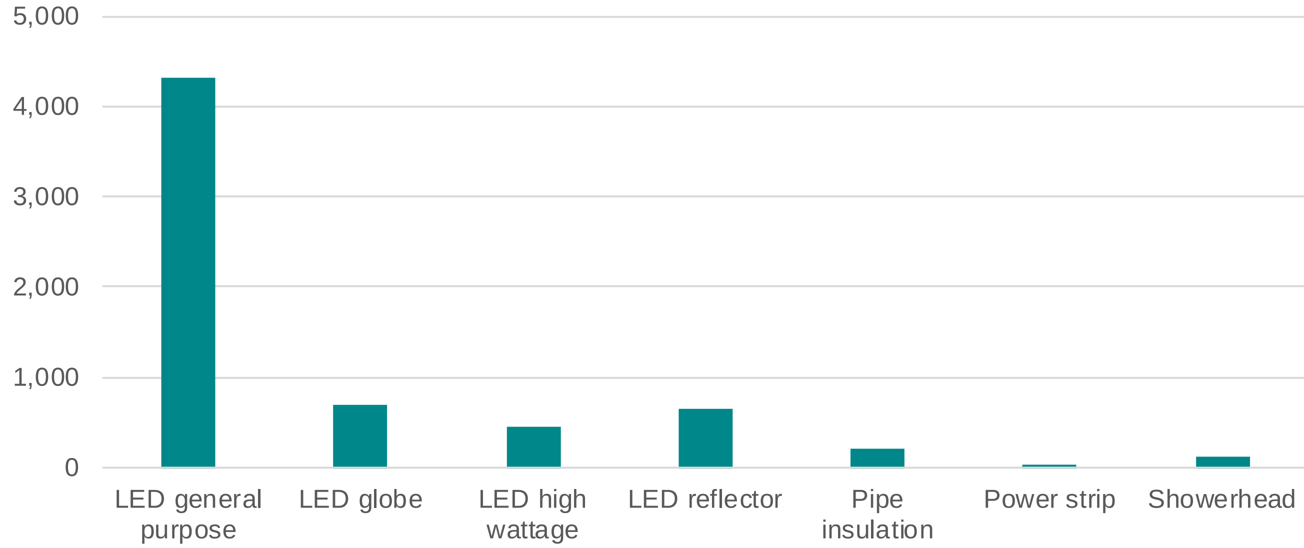


Figure 28. Home Energy Audit measures installed in participating homes

The QA goal for the program was inspection of 5 percent of all audits, translating into approximately 23 audits in 2018. Ultimately, 26 QAs were completed in 2018, with all audits passing inspection.

Marketing Activities

In 2018, the Home Energy Audit marketing collateral (including bill inserts, flyers, posters, print and digital advertisements, etc.) continued the illustrated look and feel of the 2017 campaign. Idaho Power recruited participants using small batches of direct-mail letters to ensure customers who sign up are contacted within a short timeframe and to avoid a large backlog of work which could result in a poor customer experience.

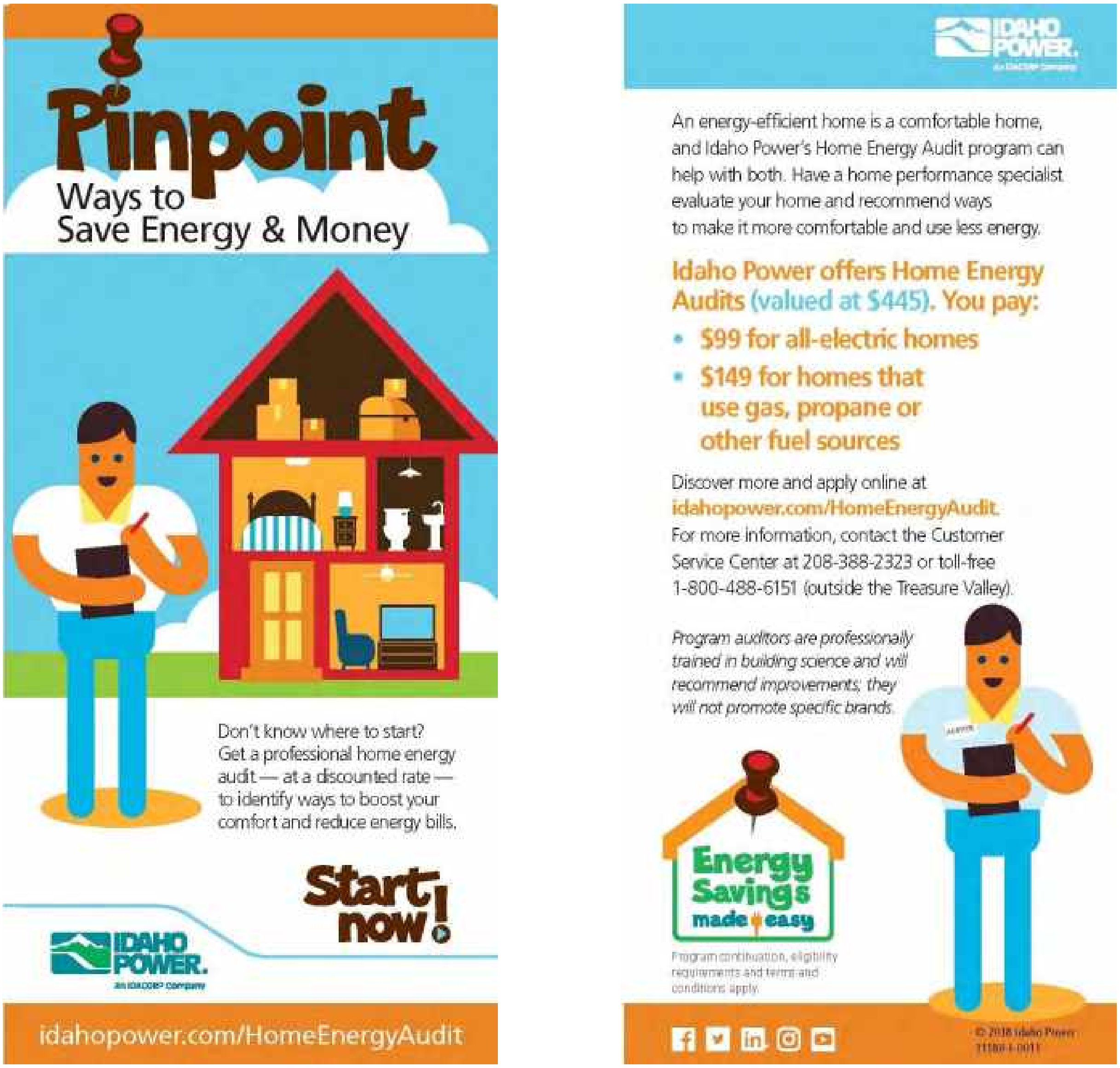


Figure 29. Home Energy Audit program bill insert

In November 2018, Idaho Power collaborated with the University of Idaho's Valley County Extension Office to host an energy efficiency workshop in Cascade, Idaho. Letters were sent to residents inviting the community to attend the afternoon and evening workshops. The workshop was attended by approximately 12 residents and was well received. Attendees learned how to check their homes for efficiency, how to make improvements, what incentives are available through Idaho Power, and how a professional energy assessment could help improve energy efficiency. Each participant received a Giveaway ESK.

Program-related bill inserts were sent to 334,335 residential customers in March, 329,995 customers in June, and 325,425 in December. The program was prominently featured in the overall energy efficiency residential marketing campaign, including a specific call-out in the television, print, and digital advertisements. The company also featured the Home Energy Audit in an article in the October issue of *Connections*. The *2018 Summer Energy Efficiency Guide* featured ways to save energy at home and referred customers to the Home Energy Audit web page. The guide appeared in regional newspapers in July and August.

In September, digital display ads ran on a variety of websites based on user demographics, search behavior, and other targeted factors (Figure 30). The ads generated 676,000 impressions and a 0.16 percent click-through rate. In February and June, digital ads ran on Facebook and generated 55,930 and 146,757 impressions, respectively. The February ad was boosted in March, generating an additional 7,667 impressions. In June, another post about the program was boosted, resulting in 9,237 impressions. In March, KPVI in Pocatello interviewed an Idaho Power customer representative who shared information about the Home Energy Audit program.

Figure 30. Home Energy Audit program digital ad

Customers who enrolled in the Home Energy Audit program throughout the year were asked where they heard about the program. Responses included the following: information in the mail, 50 percent; other, 30 percent; family member or friend, 10 percent; Idaho Power employee, 9 percent; social media, 1 percent.

Cost-Effectiveness

One of the goals of the Home Energy Audit program is to increase participants' understanding of how their home uses energy and to encourage their participation in Idaho Power's energy efficiency programs. Since the Home Energy Audit program is primarily an educational and marketing program, the company does not apply the traditional cost-effectiveness tests to the program.

For the items installed directly in the homes, Idaho Power used RTF savings for direct-install lightbulbs, which range from 16 to 61 kWh per year. This was a slight increase over the 2017 lightbulb savings which ranged from 14 to 47 kWh per year. The savings attributed to the directly installed LEDs increased nearly 40 MWh between 2017 and 2018. This increase is offset slightly by lower savings and fewer installations of showerheads and pipe wraps. These changes account for the 36 MWh increase in total reported savings between 2017 and 2018.

The RTF savings for 2.0 gpm showerheads directly installed in an electrically water heated home are approximately 144 kWh per year. However, showerheads that were installed on non-electrically water heated homes do have a small amount of electric savings. The RTF calculates the energy saved from the water not processed at a wastewater treatment facility. The RTF estimates that a 2.0 gpm showerhead installed on a non-electric water heater saves approximately 4 kWh per year. In Idaho Power's *Energy Efficiency Potential Study,* Applied Energy Group (AEG) estimates that pipe wraps save 130 kWh per year. Savings for both showerheads and pipe wrap were counted for homes with electric water heaters.

Idaho Power contracted with DNV GL to perform an impact evaluation of the program in 2017. DNV GL recommended that Idaho Power use the pipe wrap savings of 130 kWh for from the 2016 potential study. Because of the timing of the result of that study, Idaho Power did not incorporate those savings prior to the 2018 program year. However, the pipe wrap savings from the 2016 study were used in the 2018 program year. Additionally, AEG provided new estimates for pipe wrap savings with the 2018 potential study update. These new savings will be applied in 2019.

DNV GL also recommended claiming NEBs for pipe wrap insulation and showerheads in homes with gas water heat. Idaho Power has calculated the gas and water savings for showerheads installed in gas water heat homes. While Idaho Power does not calculate a cost-effectiveness ratio for the Home Energy Audit program, those values have been included in the sector and portfolio cost-effectiveness.
Idaho Power has also converted the 130 kWh of pipe wrap savings to 4.43 therms and those gas savings are included in the sector and portfolio cost-effectiveness.

Customer Satisfaction

Throughout 2018, a survey was sent to 456 customers who had participated in the program between October 2017 and September 2018. The purpose of the survey was to assess customers' satisfaction with program enrollment, the scheduling, the auditor, the personalized report, and the information learned. Participants who supplied an email address on the initial program enrollment form were sent an electronic survey (301 participants); those without an email address were sent a hard copy of the survey with a postage-paid envelope (155 participants). The response rate was about 34 percent, with 156 participants responding.

When asked a series of questions about their experience with the program, about 90 percent of respondents "strongly agree" or "somewhat agree" they would recommend the program to a friend or relative, and nearly 91 percent of respondents "strongly agree" or "somewhat agree" they were satisfied with their overall experience with the program. Nearly 97 percent of the respondents indicated it was "very easy" or "somewhat easy" to apply for the program. Home performance specialists were rated on a number of attributes, including courteousness, professionalism, explanation of work/measurement to be performed, explanation of audit recommendations, and overall experience. Respondents rated their home performance specialist as "good" or "excellent" 90 to 99 percent of the time.

When asked how strongly they agree or disagree with statements about what they learned during the audit process, over 93 percent of respondents "strongly agree" or "somewhat agree" they were more informed about the energy use in their home. Over 77 percent reported they "strongly agree" or "somewhat agree" they were more informed about energy efficiency programs available through Idaho Power. Over 84 percent indicated they "strongly agree" or "somewhat agree" they learned what additional no-cost to low-cost actions they could take.

A copy of the survey results can be found in *Supplement 2: Evaluation.*

2019 Program and Marketing Strategies

Idaho Power will continue recruiting participants through small batches of targeted direct-mailings, social media posts, advertising, and bill inserts. Additional digital advertising may be considered if the program needs to be strategically promoted in specific regions.

Beginning January 2019, based on the results of the RFP, Idaho Power will use SnuggHome residential auditing software from SnuggPro.

Multifamily Energy Savings Program

		2018	2017
Participation and Savings			
	Participants (projects)	25	12
	Energy Savings (kWh)	655,963	617,542
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$205,131	$167,342
	Oregon Energy Efficiency Rider*	$0	$0
	Idaho Power Funds	$0	$874
	Total Program Costs—All Sources	$205,131	$168,216
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.030	$0.026
	Total Resource Levelized Cost ($/kWh)	$0.030	$0.026
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.60	1.75
	Total Resource Benefit/Cost Ratio	3.00	3.55

* Idaho Rider charges of $13,264 were reversed and charged to the Oregon Rider in March 2019. Oregon savings should have been 67,270 kWh.

Description

The Multifamily Energy Savings Program provides for the direct installation of energy-saving products in multi-family dwellings with electrically heated water in Idaho and Oregon. These energy-saving products are installed by an insured contractor hired by Idaho Power at no cost to the property owner, manager, or tenant. Idaho Power defines a multi-family dwelling as a building consisting of five or more rental units. The products installed are: ENERGY STAR® LED lightbulbs, high-efficiency TSV showerheads, kitchen and bathroom faucet aerators, and water heater pipe insulation.

To ensure energy savings and eligibility, each building is pre-approved by Idaho Power and the contractor who will install the energy efficiency measures. Upon approval, the no-cost, direct installation is scheduled and completed. Tenants in participating apartment complexes receive a tailored door hanger before the service date notifying them that contractors will be entering their home to install energy-saving products.

Program Activities

Twenty-five projects across the Idaho and Oregon service area were completed as program participation increased significantly in 2018. Between these 25 projects, a total of 810 apartment units received the energy-saving products, compared to 687 apartment units in 2017.

Marketing Activities

To increase awareness and promote participation in the Multifamily Energy Savings Program, three alternating, clickable ads were added to the Landlord/Property Manager Requests page of Idaho Power's website (Figure 31). Letters describing the program, its benefits, and eligibility requirements were mailed to targeted audiences (landlords and property owners) to further increase awareness.

Figure 31. Three Multifamily Energy Saving Program promotional ads on website

In mid-2018, a new marketing video was added to the Multifamily Energy Savings Program web page. The video explains the eligibility requirements, the no-cost direct-install measures available to landlords/tenants, the installation process, and the potential for residents to save on their monthly bills and be more comfortable in their home. Contact information is provided at the end of the video.

As customers participated in the program throughout the year, Idaho Power communicated with them before and after their installations. A pre-installation door hanger explained the schedule and the types of products a contractor would install inside the customers' homes (Figure 32). Once installation was complete, Idaho Power left materials to explain the new energy efficiency measures and to provide contact information should the tenant have any questions. Lastly, customers were asked to participate in a survey, rating their satisfaction for installed measures and overall product and program satisfaction. The responses will help Idaho Power improve marketing activities in the future.

Figure 32. Multifamily Energy Saving Program post-project customer survey

Cost-Effectiveness

The RTF provides deemed savings for direct-install LED lightbulbs and low-flow showerheads. The LED lightbulbs have a deemed savings value of 16 to 61 kWh per year depending on the type and lumens of the lightbulb and the location of the lightbulb installation. The integrated 1.75 gpm showerheads with TSV were installed in most apartments. These showerheads save approximately 267 kWh per year. Some apartments had the 2.0 gpm showerhead installed which save approximately 102 kWh. For the faucet aerator and pipe wrap, the RTF does not provide a deemed savings estimate. In Idaho Power's *Energy Efficiency Potential Study*¸ AEG estimated the annual faucet aerator savings to be 56 kWh and the annual pipe wrap savings to be 81 kWh.

In 2018, the RTF reviewed and updated the savings assumptions for LED lightbulbs and deemed savings values for faucet aerators. These new savings will be applied in 2019.

The UCT and TRC ratios for the program is 1.60 and 3.00 respectively. Impact and process evaluations were conducted for the program in 2018. If the evaluation costs incurred in 2018 were removed from the program's cost-effectiveness, the UCT and TRC ratios would be 1.96 and 3.66 respectively.

For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction

Idaho Power included a satisfaction survey with the leave-behind materials in each apartment. Both an online and mail-in option were offered. The response rate was low, with only 52 out of over 700 residents responding by mailing in the stamped survey cards; no online surveys were submitted. Residents were asked to rate several attributes on a scale with 1 being very dissatisfied to 5 being very satisfied. Overall, the residents that responded to the survey were satisfied with the project. Respondents rated the quality of the products at 4.54 and rated the overall project at 4.67.

Evaluations

In 2018, Idaho Power retained Tetra Tech to conduct an impact evaluation of 2017 reported savings and a process evaluation of current program processes. The results of the evaluations revealed a successful first-year program.

The impact evaluation found that Idaho Power used the incorrect savings values from the 2016 potential study which resulted in an overall realization rate of 84 percent. The transcribed error was corrected for the 2018 program year.

The process evaluation found that the program specialist and installation contractors work well to deliver the program. Contractors indicated that current processes effectively streamline program activity and reduce additional visits that burden property managers and tenants. They also found the program materials to be professional, informative, and educational.

Idaho Power will consider all recommendations from the process and impact evaluations; responses will be reported in the *Demand-Side Management 2019 Annual Report*. See the complete process and impact evaluation report in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

Idaho Power plans to increase energy-efficient direct-installation projects in multi-family dwellings throughout its service area in 2019. Following a suggestion from EEAG, Idaho Power anticipates adding attic insulation to the list of direct-install measures in 2019. To qualify, current insulation must be rated R7 or below.

Idaho Power will continue to use informative notifications, pre-installation door hangers, and post-installation informational marketing pieces as well as survey cards. Direct-mailings will be continued to encourage engagement and participation from property owners/managers and to increase program visibility.

Oregon Residential Weatherization

		2018	2017
Participation and Savings			
	Participants (audits/projects)	5	7
	Energy Savings (kWh)	n/a	2,154
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$5,507	$2,384
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$5,507	$2,384
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	$0.063
	Total Resource Levelized Cost ($/kWh)	n/a	$0.099
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a program required by Oregon Revised Statute (ORS) 469.633 and has been offered under Oregon Tariff Schedule 78 since 1980. Upon request, an energy audit contractor hired by Idaho Power visits the customer's home to perform a basic energy audit and analyze it for energy efficiency opportunities. An estimate of costs and savings for recommended energy efficient measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

Program Activities

In 2018, five customers returned a card from the program brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. All five of these customers met the program requirements and received audits, though none chose to move forward with the recommended energy efficiency upgrades. Therefore, no loans or incentives were issued in 2018.

Marketing Activities

During May, as required, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing.

Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program described in Oregon Schedule 78, which includes a cost-effectiveness definition of this program. Pages three and four of the schedule identify the measures determined to be cost-effective and the specified measure life cycles for each. This schedule also includes the cost-effective limit (CEL) for measure lives of seven, 15, 25, and 30 years.

No audits translated to efficiency projects in 2018.

2019 Program and Marketing Strategies

Idaho Power will complete requested audits, fulfill all incentives deemed cost-effective, and process loan applications as required under Tariff Schedule 78. The company will market the program to customers with a bill insert/brochure and add a program web page to the Savings For Your Home section of the Idaho Power website in 2019.

Rebate Advantage

		2018	2017
Participation and Savings			
	Participants (participants)	107	66
	Energy Savings (kWh)	284,559	214,479
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$105,770	$93,891
	Oregon Energy Efficiency Rider	$41,714	$10,861
	Idaho Power Funds	$0	$244
	Total Program Costs—All Sources	$147,483	$104,996
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.027	$0.025
	Total Resource Levelized Cost ($/kWh)	$0.064	$0.055
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.93	1.88
	Total Resource Benefit/Cost Ratio	1.08	1.19

Description

Initiated in 2003, the Rebate Advantage program helps Idaho Power customers in Idaho and Oregon with the initial costs associated with purchasing a new, energy-efficient, ENERGY STAR® qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. The program also provides an incentive to the sales consultants to encourage more sales of ENERGY STAR qualified homes and more discussion of energy efficiency with their customers during the sales process.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured (NEEM) housing program establishes quality control (QC) and energy efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

Program Activities

In 2018, the residential customer incentive for this program was $1,000; the sales staff incentive was $200 for each qualified home they sold. Idaho Power paid 107 incentives on new manufactured homes, which accounted for 284,559 annual kWh savings. This included a 32-home development in Ontario, Oregon.

Marketing Activities

In March, Rebate Advantage was promoted through a bill insert (shared with the Energy House Calls program) sent to 345,506 customers. The insert had information about the potential energy and dollar savings to customers and referred customers to the program website.

In May 2018, the company updated Rebate Advantage program collateral, including flyers and posters. Idaho Power continued to support manufactured home dealerships by providing them with updated Rebate Advantage collateral, as well as 10 vinyl banners (Figure 33).

Figure 33. Rebate Advantage dealership banner

A Facebook ad ran in September aimed at reaching Spanish- and English-speaking customers age 35-65+ with at least a high school education and an interest in manufactured housing. The ad reached 11,836 people and resulted in 38,444 impressions.

Cost-Effectiveness

The Rebate Advantage program has a UCT of 1.93 and a TRC of 1.08. In February 2017, the RTF updated savings for new construction manufactured homes. The RTF updated the heating system measure identifier for these new manufactured homes. Previously, the savings for these homes differed by heating system type: electric forced air furnace vs. heat pump. The RTF models savings for the new home "shell." When compared to an inefficiently built home, efficient homes with an electric forced-air furnace technically save more energy than those built with a heat pump because the savings come from the shell and not the heating source. The RTF was concerned that while manufactured homes would leave the factory with an electric forced-air furnace; some of these homes would have a heat pump installed within a year. If this would occur, savings could be double counted within Rebate Advantage and H&CE Program. To address this, the RTF blended the heating system type to be split 75 percent forced-air furnace and 25 percent heat pump. As a result, the average annual savings per home declined by 18 percent between 2017 and 2018.

For detailed information for all measures within the Rebate Advantage program, see *Supplement 1: Cost-Effectiveness*.

2019 Program and Marketing Strategies

Idaho Power will continue to support manufactured home dealers by providing them with program materials. The company will also distribute a bill insert to Idaho and Oregon customers and will explore digital advertising to promote the program to potential manufactured home buyers.

Residential New Construction Pilot Program

		2018	2017
Participation and Savings			
	Participants (participants)	307	277
	Energy Savings (kWh)	777,369	608,292
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$400,910	$320,637
	Oregon Energy Efficiency Rider	$2	$2,232
	Idaho Power Funds	$0	$651
	Total Program Costs—All Sources	$400,912	$323,520
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.027	$0.028
	Total Resource Levelized Cost ($/kWh)	$0.061	$0.051
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.51	2.36
	Total Resource Benefit/Cost Ratio	1.23	1.47

Description

The Residential New Construction Pilot Program launched in March 2018, replacing the ENERGY STAR® Homes Northwest Program. The Residential New Construction Pilot Program offers builders a cash incentive to build energy-efficient, single-family homes that use heat pump technology in Idaho Power's Idaho service area. These homes must meet strict requirements that make them at least 20 percent more energy efficient than homes built to standard state energy code.

The RTF and NEEA have created specific modeling requirements and program guidelines to ensure the program provides reliable energy savings for utilities across the Northwest. These homes feature high-performance HVAC systems, high-efficiency windows, increased insulation values, and tighter building shells to improve comfort and save energy. Idaho Power claims energy savings based on each home's individual modeled savings.

Builders must contract with a Residential Energy Services Network (RESNET)-certified rater to ensure the home design will meet program qualifications. The rater will work with the builder from the design stages through project completion; perform the required energy modeling using REM/Rate modeling software; perform site inspections and tests; and enter, maintain, and submit all required technical documentation in the REM/Rate modeling software and the AXIS database. This data is used to determine the energy savings and the percent above code information needed to certify the home. NEEA maintains the regional AXIS database.

Program Activities

The ENERGY STAR® Homes Northwest Program was phased out in 2018, and only homes that were started prior to January 31, 2018 and certified by December 31, 2018 could qualify for that incentive. Two hundred ninety-two of these homes were certified and received the $1,000 incentive in 2018.

The incentive for homes certified under the Residential New Construction Pilot Program is $1,500. The company paid incentives on 15 Residential New Construction Pilot Program homes, accounting for savings of 64,889 kWh.

Marketing Activities

Idaho Power maintained a strong presence in the building industry by supporting the Idaho Building Contractors Association (IBCA) and several of its local affiliates throughout Idaho Power's service area in 2018. The company participated in the IBCA Summer Board Meeting, the Building Contractors Association of Southwestern Idaho (BCASWI) builder's expo, and the Snake River Valley Building Contractors Association (SRVBCA) builder's expo.

Idaho Power supported Parade of Homes events with full-page ads in the Parade of Homes magazines of the following BCAs: The Magic Valley Builders Association (MVBA), the BCASWI, and the SRVBCA. A print ad was created for the Pocatello Parade of Homes and a poster for the Twin Falls Home Show. Print and digital ads also appeared in the *Idaho Business Review* in June (Figure 34).

Figure 34. Residential New Construction Pilot Program ad

On the April and May billing statements, Idaho Power added messages informing residential customers of Parade of Homes events in their area. A bill insert was sent to 342,687 Idaho customers in May to promote the program.

New informational program brochures and a new program web page were created in March to educate and inform program stakeholders and customers of the new program.

Cost-Effectiveness

Residential New Construction cost-effectiveness improved in 2018 because of increased savings and decreased incremental costs. The RTF updated prescriptive deemed savings numbers for new construction townhomes for Idaho and Montana in spring of 2017. The increase savings from 2,196 to 2,440 annual kWh better reflected Idaho building code baselines. The updated RTF savings were applied to the 292 legacy ENERGY STAR® homes submitted by builders in 2018. Savings for the 15 energy-modeled homes varied between 2,100 and 8,700 kWh per home depending on which efficiency upgrades were included to meet the 20-percent over code program requirement.

Incremental costs of efficient measures dropped by over $400 per home for legacy homes contributing to improved benefit-cost ratios. Incremental costs for the 15 modeled homes were calculated on a project-by-project basis looking at the average upgrades in efficiency within the two communities. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

2019 Program and Marketing Strategies

Idaho Power plans to continue to promote this program to Idaho builders and new home buyers. These marketing efforts include ads in Parade of Homes magazines for the BCASWI, SRVBCA, MVBA, and the Building Contractors Association of Southeast Idaho (BCASEI). A bill insert is planned for spring 2019. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Social media and other advertising will be considered based on past effectiveness.

Shade Tree Project

	2018	2017
Participation and Savings		
Participants (trees)	2,093	2,711
Energy Savings (kWh)	35,571	n/a
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$162,995	$194,695
Oregon Energy Efficiency Rider	$0	$0
Idaho Power Funds	$0	$1,122
Total Program Costs—All Sources	$162,995	$195,817
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.307	n/a
Total Resource Levelized Cost ($/kWh)	$0.307	n/a
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	0.71	n/a
Total Resource Benefit/Cost Ratio	0.80	n/a

Description

The Shade Tree Project began as a pilot in 2013. According to the DOE, a well-placed shade tree can reduce energy used for summer cooling by 15 percent or more. Utility programs throughout the country report high customer satisfaction with shade tree programs and an enhanced public image for the utility related to sustainability and environmental stewardship. Other utilities report energy savings between 40 kWh per year (coastal climate San Diego) and over 200 kWh per year (Phoenix) per tree planted.

To be successful, trees should be planted to maximize energy savings and ensure survivability. Two technological developments in urban forestry—the state-sponsored Treasure Valley Urban Tree Canopy Assessment and the Arbor Day Foundation's Energy-Saving Trees tool—provided Idaho Power with the information to facilitate a shade tree project.

The Shade Tree Project operates in a small geographic area each spring and fall, offering no-cost shade trees to residential customers. Participants enroll using the online Energy-Saving Trees tool and pick up their tree at specific events. Unclaimed trees are donated to cities and schools.

Using the online enrollment tool, participants locate their home on a map, select from a list of available trees, and evaluate the potential energy savings associated with planting in different locations. During enrollment, participants learn how trees planted to the west and east save more energy over time than trees planted to the south and north.

Ensuring the tree is planted properly helps it grow to provide maximum energy savings. At the tree pickup events, participants receive additional education on where to plant trees for maximum energy savings and other tree care guidance from experts. Local specialists include city arborists from participating municipalities; Idaho Power utility arborists; county master gardeners; and College of Southern Idaho horticulture students.

Each fall, Idaho Power sends participants from the previous two offerings a newsletter filled with reminders on proper tree care and links to resources, such as tree care classes and educational opportunities in the region. This newsletter was developed after the 2015 field audits identified common customer tree care questions and concerns.

Program Activities

In 2018, Idaho Power expanded the Shade Tree Project to include additional counties. In the spring, the project was open to customers in Twin Falls, Jerome, Gooding, Camas, Lincoln, Minidoka, and Cassia counties. In the fall, the project was open to customers in Ada, Canyon, Elmore, Gem, Payette, Owyhee, and Washington counties. Overall, Idaho Power distributed 2,093 trees to residential customers through the Shade Tree Project. Because the best time to plant shade trees is in the spring and fall, Idaho Power held offerings in April and October, with 954 trees and 1,139 trees distributed, respectively.
Idaho Power purchased the trees from a local wholesale nursery in advance of each event. The species offered for each event depended on the trees available at the time of purchase. Idaho Power worked with city and state arborists to select a variety of large-growing, deciduous trees that traditionally grow well in the climate and soils of the participating counties.

Participants picked up the trees at events throughout the project area—two in the spring and four in the fall. Staging several pickup days, locations, and times helps maximize the number of trees picked up. In 2018, 85 percent of all trees were distributed to homeowners.

Idaho Power continues to track the program data in the DSM database. The database is also used to screen applicants during enrollment to determine whether participants meet the eligibility requirements for the project, such as residential status within the eligible counties (customer type and location).

Marketing Activities

For both spring and fall offerings, Idaho Power developed a direct-mailing list using Idaho Power customer information to identify customers who lived in a house that had been constructed within the last 10 years. Approximately 8,330 direct-mailers were sent to targeted customers in the spring and 9,501 in the fall.

For both offerings, Idaho Power also sent emails to customers who had requested information about the project through Idaho Power's website. The cities of Nampa, Meridian, Boise, and Payette shared information through their networks. Idaho Power announced its Shade Tree Project to the Treasure Valley Canopy Network. The company also distributed program flyers at local events, where appropriate, and created a vinyl banner for the first event held in Twin Falls.

A cloth poster was available in 2018 to showcase what each tree would look like at full maturity and was a useful reference for customers who had questions. In June, the program was featured in *Connections*, citing the recent visit to Twin Falls and directing customers to the program website to sign up to be notified of future events.

Each recipient of a shade tree received a packet containing planting directions, tips, illustrations, and other useful information. In September 2018, a newsletter was sent to the last season's program participants. Articles discussed the expansion of the program to new locations and tips on how to keep trees healthy. The company also ran a social media post in April thanking the participants and host who made the Twin Falls event a success (Figure 35). The program was also promoted in the *Home Energy Reports*.

Figure 35. Thank-you post from Idaho Power after Twin Falls Shade Tree Project event

Cost-Effectiveness

For the Shade Tree Project, Idaho Power utilizes the Arbor Day Foundation's software which calculates energy savings and other NEBs based on tree species and orientation and distance from the home. This tool, i-Tree software, estimates these benefits for years 5, 10, 15, and 20 after the tree planting year. However, the savings from the tool assumes that each tree is planted as planned. In 2018, Idaho Power contracted with DNV GL to evaluate the program to determine a realization rate based on the survival rate for these trees and to develop a model to calculate average values per tree.

The cost-effectiveness for the program is based on the modeled savings for the tree distributed in 2018 and the costs incurred during 2018. As shown in Table 11, it is estimated these trees will begin saving 35,425 kWh in 2022 and 116,197 kWh by year 2038. Based on the model, the project has as UCT ratio of 0.71 and a TRC ratio of 0.80.

For the calculator, DNV GL assumed a measure life of 20 years. This is because i-Tree software only estimates saving at 5, 10, 15, and 20 years. In 2018, the bur oak, northern red oak, Greenspire® littleleaf linden, and tulip tree were the most common species distributed in the project. According to the United States Department of Agriculture (USDA), a bur oak can live 300 to 400 years, and a northern red oak can live up to 500 years. The Urban Forest Ecosystem Institute estimates the littleleaf linden can live 50 to 150 years, and the tulip trees can live beyond 150 years. Idaho Power acknowledges the potential energy savings for a tree may continue to increase beyond year 20, but the savings will be capped at some point regardless of how large the tree grows. For the trees distributed in 2018, data around the survivorship beyond 2038 is also unknown. While the energy savings in 2038 is estimated to be 116,197 kWh, the savings may continue to increase at a diminishing rate before eventually declining due to increased mortality. However, if energy savings were to stay constant beyond year 20, it can be assumed that the program would be cost-effective from both the UCT and RTC perspective if the program life was revised to 30 years.

For non-energy impacts, i-Tree software estimates a monetary benefit value for improved air quality and avoided runoff from stormwater. However, these benefits are largely offset by the heating detriment caused by the winter shade from the tree that requires extra heating for the home. Also, while the tree does remove carbon dioxide from the air, there is also an increase in carbon dioxide from the increased winter home heating.

While an evaluation was conducted for the program in 2018, the evaluations costs will be incurred in 2019. At that time, Idaho Power will calculate the cost-effectiveness ratios with and without evaluation costs.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction

After each offering, a survey was emailed to participants. The survey asked questions related to program marketing, tree-planting education, and participant experience with the enrollment and tree pickup processes. Results are compared, offering to offering, to look for trends to ensure the program processes are still working, and to identify opportunities for improvement. Data are also collected about where and when the participant planted the tree. These data will be used by Idaho Power to refine energy-savings estimates.

In total, the survey was sent to 1,170 Shade Tree Project participants. The company received 696 responses for a response rate of over 59 percent. Participants were asked how much they would agree or disagree that they would recommend the project to a friend; nearly 96 percent of respondents said they “strongly agree,” and nearly 3 percent said they “somewhat agree.” Participants were asked how much they would agree or disagree that they were satisfied with the overall experience with the Shade Tree Project; over 92 percent of respondents indicated they “strongly agree,” and nearly 7 percent “somewhat agree” they were satisfied. View the complete survey results in *Supplement 2: Evaluation*.

Evaluations

In 2018, DNV GL was retained to estimate kWh savings for trees planted during program years 2013 through 2018. DNV GL reconciled program enrollment data with data obtained during Idaho Power audits of a random selection of the trees planted in 2013 to 2016. The audits recorded actual orientation and distance from the home and recalculated savings based on those actual values. The audits also provided mortality data.

DNV GL used estimated kWh savings from i-Trees software to calculate average realization rates and benefits for each planting year, by audited tree species for years 5, 10, 15, and 20 after planting. They assigned these average realization rate assumptions to the unaudited trees and calculated the evaluated savings rates. DNV GL then averaged all values per planting year to calculate the average per-tree benefits and interpolated annual per-tree average benefits for all years.

The total savings and benefits were calculated by multiplying the per-tree average savings by the number of trees planted each year and the estimated survival rate for that year. DNV GL recommends Idaho Power claim future benefits and energy savings as noted in Table 11.

Table 11. Suggested energy savings from DNV GL for the Shade Tree Project

	Incremental Annual Savings (kWh)					
Planting Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
2013	3,724	860	783	756	729	703
2014		34,511	7,974	7,253	7,006	6,759
2015			32,361	7,477	6,802	6,570
2016				34,883	8,060	7,332
2017					45,884	10,602
2018						35,425
Incremental Claimable Annual Savings*	3,724	35,371	41,118	50,370	68,482	67,390
Total Current Year Savings**	3,724	39,095	303,848	277,729	254,723	203,262
Cumulative Savings***	3,724	42,818	346,666	624,395	879,119	1,082,381

*Incremental savings over previously claimed annual savings.
**Total annual savings for trees from all planting years.
***Cumulative savings since program inception.

Idaho Power will respond to any 2018 evaluation recommendations during the 2019 program year. The complete report, including additional calendar-year savings recommendations, can be found in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2019, returning it to the Twin Falls area in the spring and expanding it to the Pocatello area for the first time in the fall. The project will use the Arbor Day enrollment tool, and trees will be distributed at multiple events.

Idaho Power will continue to market the program through direct-mail, focusing on customers identified using the Urban Tree-Canopy Assessment tool in the Treasure Valley and customer information to identify those customers who live in newly constructed homes. The program will be promoted in the April 2019 *Home Energy Report*. In addition, Idaho Power maintains a waiting list of customers who were unable to enroll because previous offerings filled. Idaho Power will reach out to these customers through direct-mail or email for the 2019 offerings. Idaho Power will continue to leverage allied interest groups and use social media and boosted Facebook posts if enrollment response rates decline.

Simple Steps, Smart Savings™

		2018	2017
Participation and Savings			
	Participants (products)	7,377	12,556
	Energy Savings (kWh)	241,215	900,171
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$86,721	$185,354
	Oregon Energy Efficiency Rider	$3,762	$5,811
	Idaho Power Funds	$0	$456
	Total Program Costs—All Sources	$90,484	$191,621
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.034	$0.020
	Total Resource Levelized Cost ($/kWh)	$0.050	$0.051
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.44	2.38
	Total Resource Benefit/Cost Ratio	4.68	5.05

Description

Initiated in 2015, the Simple Steps, Smart Savings™ program is designed to increase sales of qualified energy-efficient appliances through promotion-based incentives. Incentives are shared by the retailer, manufacturer, and the customer, though they may differ among promotions and among retailers and manufacturers.

Idaho Power may provide incentives to the retailer or manufacturer as co-marketing dollars to fund activities such as promotional events, special product placement, point-of-purchase signage, retailer activities, event kits, sales associate training, training material, and other marketing activities during the promotional periods.

Customer rewards may include, but are not limited to, retailer gift cards, free related products, or reduced pricing. Each promotion is available in Idaho and Oregon.

Idaho Power also participates in the BPA-sponsored, Simple Steps, Smart Savings energy-efficient lighting program, which is discussed further in the Energy Efficient Lighting program section of this report. All Simple Steps, Smart Savings promotions are administered by the BPA and coordinated by a third-party contractor, CLEAResult.

Program Activities

In 2018, the qualified products included select ENERGY STAR® rated clothes washers and high-efficiency showerheads. The incentive provided by Idaho Power through this program for clothes washers was applied during special promotions, which aligned with holidays or events throughout the year at retail stores. The promotion for showerheads ran the entire year.

Appliances

In 2018, Idaho Power participated in five major Simple Steps, Smart Savings appliance promotions with these retailers: Sears, Sears Hometown, and RC Willey.

At each event, CLEAResult personnel staffed a table and answered customer questions about the appliance promotion. To further educate customers about the promotions, CLEAResult created an Idaho Power-branded promotional landing page that highlights promotion details and participating retailers.

The five promotions took place as follows: 1) the 2017 Black Friday promotion took place in November through the first week of December—because invoice of sales for this promotion is not received until the following month, they are included with the remaining four 2018 promotions; 2) the President's Day promotion ran for two weeks in February; 3) the Memorial Day promotion ran the last week in May through the first week in June; 4) the Independence Day promotion ran the last week in June through the first two weeks in July; and 5) the Labor Day promotion ran the last week in August through the first week in September. In-store events were held at all participating retailers in Idaho Power's service area during the promotions.

Incentives for the purchase of a qualified ENERGY STAR clothes washer included a $25 gift card at Sears, a $25 instant markdown at Sears Hometown, and a $25 gift card at RC Willey. RC Willey added $10 to the $25 provided to allow them to offer a $35 gift card to customers for the first three promotions. The additional $10 was not included in the incentive for the Independence Day and Labor Day promotions.

Showerheads

In 2018, Idaho Power worked with seven participating retailers on the high-efficiency showerhead promotion. There were 6,558 qualified showerhead sales, as compared to 11,528 in 2017. Of those sales, 14 percent were 1.50 gpm, 8 percent were 1.75 gpm, and 78 percent were 2.0 gpm showerheads. One possible reason for the large decrease in showerhead sales may be a result of the reduction in incentive amount from 2017 to 2018. In 2017, customers received a $7 instant markdown for the purchase of a qualified showerhead. In 2018, the instant markdown incentive was decreased to $6 for 1.75 and 1.50 gpm showerheads and $2 for 2.0 gpm showerheads.

Marketing Activities

To help support the appliance promotions, table tents and static clings were displayed on all qualifying appliances. These pieces informed customers about the promotion and the incentive they would receive. In-store gift cards were placed in gift card holders that displayed the Idaho Power logo. For purchases from Sears Hometown, where the customer received an instant markdown, customers also received a thank-you card with the Idaho Power logo. Additionally, CLEAResult field support staffed a table at 15 appliance promotion events to educate customers and sales staff of the Idaho Power incentives.

Several Simple Steps, Smart Savings promotions were conducted through CLEAResult at retail stores in 2018. These promotions generally involved special product placement and signs. CLEAResult staff continued to conduct monthly store visits in 2018 to check on stock, point-of-purchase signs, and displays.

During the promotions, Idaho Power placed Facebook and Twitter posts to notify customers of the details. Idaho Power posted information about the appliance promotions on its Appliances web page and promoted ENERGY STAR washers in its winter *Energy Efficiency Guide*.

Cost-Effectiveness

In late 2016, the RTF reviewed and updated the savings assumptions for showerheads. Due to the timing of the RTF update, BPA and CLEAResult implemented the new savings in 2018. Previously, the annual savings for showerheads ranged between 65 to 111 kWh. Based on the new workbook, showerhead annual savings are now between 15 and 64 kWh. The parameters that impacted the savings for showerheads include assumptions regarding the baseline showerhead, installation rate, and shower duration. As with past RTF workbooks, Idaho Power adjusts the assumptions regarding electric water heating saturation from the regional average of 60 percent to the company's average of 49 percent from the 2016 residential end-use study.

Despite the reduction in savings, showerheads remain cost-effective because there is no incremental cost between the efficient showerhead and the baseline showerhead. The RTF researched the pricing for showerheads and found that the cost did not differ significantly between similar models with varying flow rates.

The clothes washer assumptions did not change between 2017 and 2018. Idaho Power applied the per-unit savings from the approved BPA unit energy savings (UES) Measure List. While BPA applies the annual generator busbar savings of 109 kWh per unit, Idaho Power applies the annual site savings of 101 kWh per unit. This difference is due to the different line losses applied by Idaho Power and BPA. For the NEBs, Idaho Power used RTF's clothes washer workbook to determine the water and wastewater savings for the ENERGY STAR clothes washers.

For detailed information for all measures within the Simple Steps, Smart Savings program, see *Supplement 1: Cost-Effectiveness*.

2019 Program and Marketing Strategies

Idaho Power has committed to participate in the 2019 Simple Steps, Smart Savings appliance promotions, providing incentives only for products that meet Idaho Power's cost-effectiveness requirements. In 2019, the appliance promotion will work on becoming a year-round promotion. Beginning in February, RC Willey plans to begin offering incentives on qualified products throughout the year. CLEAResult will work with Sears Hometown and Lowe's to finalize contracts to begin offering the promotion year-round at their stores. Idaho Power and CLEAResult are in the process of contacting additional retailers to determine interest levels.

Idaho Power will also continue participation in the Simple Steps, Smart Savings energy-efficient showerheads buy-down program in 2019.

CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, Idaho Power-branded gift card holders, and thank-you cards. Idaho Power will notify customers of the promotions on its website, Facebook, and Twitter pages.

Weatherization Assistance for Qualified Customers

		2018	2017
Participation and Savings			
	Participants (homes/non-profits)	193	203
	Energy Savings (kWh)	649,505	669,538
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$1,272,973	$1,307,485
	Total Program Costs—All Sources	$1,272,973	$1,307,485
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.111	$0.111
	Total Resource Levelized Cost ($/kWh)	$0.159	$0.152
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.43	0.37
	Total Resource Benefit/Cost Ratio	0.52	0.48

Description

The WAQC program provides financial assistance to regional CAP agencies in Idaho Power's service area. This assistance helps fund weatherization costs of electrically heated homes occupied by qualified customers who have limited incomes. Weatherization improvements enable residents to maintain a more comfortable, safe, and energy-efficient home while reducing their monthly electricity consumption. Improvements are available at no cost to qualified customers who own or rent their homes. These customers also receive educational materials and ideas on using energy wisely in their homes. Local CAP agencies determine participant eligibility according to federal and state guidelines. The WAQC program also provides limited funds to weatherize buildings occupied by non-profit organizations that serve primarily special-needs populations, regardless of heating source, with priority given to the electrically heated.

In 1989, Idaho Power began offering weatherization assistance in conjunction with the State of Idaho Weatherization Assistance Program (WAP). In Oregon, Idaho Power offers weatherization assistance in conjunction with the State of Oregon WAP. This allows CAP agencies to combine Idaho Power funds with federal LIHEAP weatherization funds to serve more customers with special needs in electrically heated homes.

Idaho Power has an agreement with each CAP agency in the service area for the WAQC program that specifies the funding allotment, billing requirements, and program guidelines. Currently, Idaho Power oversees the program in Idaho through five regional CAP agencies: Eastern Idaho Community Action Partnership (EICAP), El Ada Community Action Partnership (EL ADA), Metro Community Services (Metro Community), South Central Community Action Partnership (SCCAP), and Southeastern Idaho Community Action Agency (SEICAA). In Oregon, Community Connection of Northeast Oregon, Inc. (CCNO), and Community in Action (CINA) provide weatherization services for qualified customers.

The Idaho Department of Health and Welfare (IDHW) uses the DOE-approved energy audit program (EA5) for the Idaho WAP and, therefore, the Idaho CAP agencies use the EA5. The EA5 is energy audit software approved for use by the DOE.

Annually, Idaho Power requires physical verification of approximately 10 percent of the homes weatherized under the WAQC program. This is done through two methods. The first method uses Idaho's and Oregon's state monitoring process that reviews weatherized homes. Utility representatives; weatherization personnel from the CAP agencies; CAPAI; and a Building Performance Institute (BPI)-certified quality control inspector review homes weatherized by each of the CAP agencies. The quality control inspector is hired by the state to ensure measures were installed to DOE and state WAP specifications.

For the second method, Idaho Power contracts with two companies—Kent Kearns Enterprises and Momentum, LLC (Momentum)—that employ building performance specialists to verify installed measures in customer homes. Kent Kearns Enterprises verifies homes weatherized for the WAQC program in Idaho Power's eastern and southern Idaho regions. Momentum verifies weatherization services provided through the WAQC program in the Capital and Canyon–West regions of Idaho and in the company's Oregon service area. After these companies verify installed measures, any required follow-up is done by CAP agency personnel.

Idaho Power reports the activities related to the WAQC program in compliance with IPUC Order No. 29505, as updated in Case No. IPC-E-16-30, Order No. 33702. This order approved Idaho Power's request to modify Order No. 29505 to consolidate the WAQC Annual Report with the DSM Annual Report each year.

This report includes the following required topics:

- Review of weatherized homes and non-profit buildings by county
- Review of measures installed
- Overall cost-effectiveness
- Customer education and satisfaction
- Plans for 2019

Program Activities

Weatherized Homes and Non-Profit Buildings by County

In 2018, Idaho Power made $1,315,372 available to Idaho CAP agencies. Of the funds provided, $1,184,987 were paid to Idaho CAP agencies in 2018, while $130,384 were accrued for future funding. Of the funds paid in 2018, $1,041,175 directly funded audits, energy efficiency measures, and health and safety measures for qualified customers' homes (production costs) in Idaho, and $104,117 funded administration costs to Idaho CAP agencies for those homes weatherized.

These funds provided for the weatherization of 188 Idaho homes and two Idaho non-profit buildings. The production cost of the non-profit building weatherization measures was $36,085, while $3,609 in administrative costs were paid for the Idaho non-profit building weatherization jobs. In Oregon, Idaho Power paid $11,805 in production costs for three qualified homes and $1,181 in CAP agency administrative costs for homes in Malheur County. Table 12 shows each CAP agency, the number of homes weatherized, production costs, the average cost per home, administration payments, and total payments per county made by Idaho Power.

Table 12. WAQC activities and Idaho Power expenditures by agency and county in 2018

Agency/County	Number of Homes	Production Cost	Average Cost	Administration Payment to Agency	Total Payment
Idaho Homes					
EICAP					
Lemhi	3	$ 11,625	$ 3,875	$ 1,163	$ 12,788
Agency Total	**3**	**$ 11,625**	**$ 3,875**	**$ 1,163**	**$ 12,788**
EL ADA					
Ada	58	331,742	5,720	33,174	364,917
Elmore	20	120,555	6,028	12,056	132,611
Owyhee	13	64,501	4,962	6,450	70,951
Agency Total	**91**	**$ 516,799**	**$ 5,679**	**$ 51,680**	**$ 568,479**
Metro Community Services					
Boise	2	7,240	3,620	724	7,964
Canyon	24	137,944	5,748	13,794	151,738
Gem	3	19,446	6,482	1,944	21,391
Payette	3	12,559	4,186	1,255	13,815
Valley	16	95,987	5,999	9,598	105,586
Agency Total	**48**	**$ 273,177**	**$ 5,691**	**$ 27,318**	**$ 300,494**
SCCAP					
Blaine	2	11,016	5,508	1,101	12,118
Gooding	6	33,819	5,636	3,382	37,200
Jerome	4	36,046	9,011	3,604	39,650
Twin Falls	15	88,071	5,871	8,807	96,878
Agency Total	**27**	**$ 168,952**	**$ 6,257**	**$ 16,895**	**$ 185,847**
SEICAA					
Bannock	9	29,767	3,307	2,977	32,744
Bingham	8	30,559	3,820	3,056	33,615
Power	2	10,296	5,148	1,030	11,325
Agency Total	**19**	**$ 70,622**	**$ 3,717**	**$ 7,062**	**$ 77,685**
Total Idaho Homes	**188**	**$ 1,041,175**	**$ 5,538**	**$ 104,117**	**$ 1,145,293**
Non-Profit Buildings					
Twin Falls	1	24,042	24,042	2,404	26,446
Power	1	12,043	12,043	1,204	13,248
Total Non-Profit Buildings	**2**	**$ 36,085**	**$ 18,043**	**$ 3,609**	**$ 39,694**
Oregon Homes					
CCNO					
Baker	0	0	0	0	0
Agency Total	**0**	**$ 0**	**0**	**$ 0**	**$ 0**
CINA					
Malheur	3	11,805	3,935	1,181	12,986
Agency Total	**3**	**$ 11,805**	**$ 3,935**	**$ 1,181**	**$ 12,986**

Agency/County	Number of Homes		Production Cost		Average Cost		Administration Payment to Agency		Total Payment
Total Oregon Homes	**3**	**$**	**11,805**	**$**	**3,935**	**$**	**1,181**	**$**	**12,986**
Total Program	**193**	**$**	**1,089,066**	**$**	**5,643**	**$**	**108,907**	**$**	**1,197,972**

Note: Dollars are rounded.

The base funding for Idaho CAP agencies is $1,212,534 annually, which does not include carryover from the previous year. Idaho Power's agreements with CAP agencies include a provision that identifies a maximum annual average cost per home up to a dollar amount specified in the agreement between the CAP agency and Idaho Power. The intent of the maximum annual average cost allows the CAP agency flexibility to service some homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes. The average cost per home weatherized is calculated by dividing the total annual Idaho Power production cost of homes weatherized by the total number of homes weatherized that the CAP agencies billed to Idaho Power during the year.
The maximum annual average cost per home the CAP agencies were allowed under the 2018 agreement was $6,000. In 2018, Idaho CAP agencies had a combined average cost per home weatherized of $5,538. In Oregon, the average was $3,935 per home weatherized.

There is no maximum annual average cost for the weatherization of buildings occupied by non-profit agencies.

CAP agency administration fees are equal to 10 percent of Idaho Power's per-job production costs. The average administration cost paid to agencies per Idaho home weatherized in 2018 was $554, and the average administration cost paid to Oregon agencies per Oregon home weatherized during the same period was $394. Not included in this report's tables are additional Idaho Power staff labor, marketing, home verification, and support costs for the WAQC program totaling $49,218 for 2018. These expenses were in addition to the WAQC program funding requirements in Idaho specified in IPUC Order No. 29505.

In compliance with IPUC Order No. 29505, WAQC program funds are tracked separately, with unspent funds carried over and made available to Idaho CAP agencies in the following year. In 2018, $102,838 in unspent funds from 2017 were made available for expenditures in Idaho. Table 13 details the funding base and available funds from 2017 and the total amount of 2018 spending.

Table 13. WAQC base funding and funds made available in 2018

Agency		2018 Base		Available Funds from 2017		Total 2018 Allotment		2018 Spending
Idaho								
EICAP	$	12,788	$	0	$	12,788	$	12,788
EL ADA		568,479		0		568,479		568,479
Metro Community Services*		302,259		-1,765		300,494		300,494
SCCAP		167,405		70,397		237,802		185,847
SEICAA		111,603		7,871		119,474		77,685
Non-profit buildings		50,000		26,334		76,334		39,694
Idaho Total	**$**	**1,212,534**	**$**	**$102,838**	**$**	**$1,315,372**	**$**	**$1,184,987**

Note: Dollars are rounded.

*Overspending of Metro Community Services in 2017 was deducted from 2018 MCS base funding.

Weatherization Measures Installed

Table 14 details home and non-profit building counts for which Idaho Power paid all or a portion of each measure cost during 2018. The home counts column shows the number of times any percentage of that measure was billed to Idaho Power during the year. If totaled, measure counts would be higher than total homes weatherized because the number of measures installed in each home varies.

WAQC and other state Weatherization Assistance Programs nationwide are whole-house programs that offer several measures that have costs but do not necessarily save energy, or for which the savings cannot be measured. Included in this category, as required by DOE, are health and safety measures and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a home's existing indoor air quality. Idaho Power contributes funding for the installation of items that do not save energy such as smoke and carbon monoxide detectors, vapor barrier, electric panel upgrades, floor registers, boots, kitchen range fans, and venting of bath and laundry areas. While these items increase health, safety, and comfort and are required for certain energy-saving measures to work properly, they increase costs of the job.

Table 14. WAQC review of measures installed in 2018

	Home Counts	Production Costs
Idaho Homes		
Audit	133	$ 17,052
Ceiling Insulation	79	68,597
CFLs	46	1,639
Doors	94	69,497
Ducts	39	24,205
Floor Insulation	46	55,500
Furnace Repair	4	626
Furnace Replacement	139	571,223
Health and Safety	25	7,305
Infiltration	111	38,714
Other	24	26,898
Pipes	18	1,640
Refrigerator Replacement	2	1,920
Vents	11	1,031
Wall Insulation	5	1,229
Water Heater	4	5,284
Windows	91	148,817
Total Idaho Homes		**$ 1,041,175**
Oregon Homes		
Ceiling Insulation	1	1,577
CFLs	1	51
Ducts	2	774
Floor Insulation	3	8,065
Health and Safety	1	561
Infiltration	3	778
Windows	0	0
Total Oregon Homes		**$ 11,805**

	Home Counts		Production Costs
Idaho Non-Profits			
Audit	2		1,033
Ceiling Insulation	2		3,553
CFLs	0		0
Doors	1		1,718
Ducts	2		4,868
Floor Insulation	1		222
Furnace Replacement	1		4,082
Health and Safety	1		483
Infiltration	2		2,720
Other	2		9,064
Pipes	1		816
Vents	1		41
Wall Insulation	1		1,725
Windows	2		5,761
Total Idaho Non-Profit Measures		**$**	**36,085**

Note: Dollars are rounded.

Marketing Activities

Idaho Power developed and distributed a brochure that provided information about both the WAQC program and Weatherization Solutions for Eligible Customers program. This was meant to help customers realize the company offers more than one way to qualify for weatherization services. Idaho Power actively informed customers about WAQC through energy and resource fairs and other customer contacts, including communication from its Customer Service Center. Information about WAQC is located on the Income Qualified Customers page of Idaho Power's website.

Cost-Effectiveness

Program cost-effectiveness increased in 2018 from both the utility cost and total resource cost perspective. The utility cost ratio ticked up to 0.43 from 0.37, and the TRC B/C ratio increased to 0.52 from 0.48. Cost-effectiveness ratios will decline slightly again in 2019 with full adoption of the 2017 IRP DSM alternate cost assumptions.

Table 15 shows the updated results that identify the difference between homes that received weatherization only vs. homes that were weatherized and upgraded with an efficient heat pump.

Table 15. 2018 savings values for WAQC program

	Weatherization only		Weatherization and heating system change	
Home Type	**kWh/project**	**kWh/ft^2**	**kWh/project**	**kWh/ft^2**
Single-family Homes	1,797	1.16	4,154	2.48
Manufactured Homes	1,734	1.36	4,418	4.30
Multi-family Homes	n/a	1.16	n/a	2.48
Non-profit Buildings	n/a	1.16	n/a	2.48

There were no changes to the values used for reporting between 2016 to 2018. The savings values were updated in 2016 to better align savings by home type and measures installed with the associated installation costs. Per-home savings were updated in late 2018 using 2015 through 2017 weatherization project energy consumption data to keep savings in line with home size, measure bundles, and furnace replacements occurring in the field.

While final cost-effectiveness is calculated based on measured consumption data, cost-effectiveness screening begins during the initial contacts between CAP agency weatherization staff and the customer. In customer homes, the agency weatherization auditor uses the EA5 to conduct the initial audit of potential energy savings for a home. The EA5 compares the efficiency of the home prior to weatherization to the efficiency after the proposed improvements and calculates the value of the efficiency change into a savings-to-investment ratio (SIR). The output of the SIR is similar to the PCT ratio. If the EA5 computes an SIR of 1.0 or higher, the CAP agency is authorized to complete the proposed measures. The weatherization manager can split individual measure costs between Idaho Power and other funding sources with a maximum charge of 85 percent of total production costs to Idaho Power. Using the audit form to pre-screen projects ensures each weatherization project will result in energy savings. The use of the audit tool drives consistent and predictable results from billing analysis of weatherization projects.

The 2018 cost-effectiveness analysis continues to incorporate the following directives from IPUC Order No. 32788:

- Applying a 100-percent net-to-gross (NTG) value to reflect the likelihood that WAQC weatherization projects would not be initiated without the presence of a program
- Claiming 100 percent of project savings
- Including an allocated portion of the indirect overhead costs
- Applying the 10-percent conservation preference adder
- Claiming $1 of benefits for each dollar invested in health, safety, and repair measures
- Amortizing evaluation expenses over a three-year period

Customer Education and Satisfaction

The CAP agency weatherization auditor explains to the customer which measures are analyzed and why. Further education is done as the crew demonstrates the upgrades and how they will help save energy and provide an increase in comfort. Idaho Power provides each CAP agency with energy efficiency guides and energy-savings tips for distribution during home visits. Any customers whose homes are selected for post-weatherization home verification receive additional information and have the opportunity to ask the home verifiers more questions.

Idaho Power used independent, third-party verification companies to ensure the stated measures were installed in the homes and to discuss the program with these customers. In 2018, home verifiers randomly selected and visited 24 homes, requesting feedback about the program. When asked how much customers learned about saving electricity, 18 customers answered they learned “a lot” or “some.”

When asked how many ways they tried to save electricity, 20 customers responded “a lot” or “some.” Three customers did not answer.

A customer survey was used to assess major indicators of customer satisfaction throughout the service area. All program participants in all regions were asked to complete a survey after their homes were weatherized. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely.

Idaho Power received survey results from 155 of 191 households weatherized by the program in 2018. Of the 155 completed surveys, 152 were from Idaho customers and three were from Oregon customers. Some highlights include the following:

- Over 35 percent of respondents learned of the program from a friend or relative, and another almost 19 percent learned of the program from an agency flyer. Nearly 5 percent learned about the weatherization program from direct-mail.
- Over 79 percent of the respondents reported that their primary reason for participating in the weatherization program was to reduce utility bills, and over 39 percent wanted to improve the comfort of their home.
- Over 76 percent reported they learned how air leaks affect energy usage, and just over 66 percent indicated they learned how insulation affects energy usage during the weatherization process.
- Over 60 percent of respondents said they learned how to use energy wisely. Eighty-five percent reported they were very likely to change habits to save energy, and almost 69 percent reported they have shared all of the information about energy use with members of their household.
- Over 91 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost 97 percent said they were very satisfied with the program.
- Over 84 percent of the respondents reported the habit they were most likely to change was turning off lights when not in use, and 67 percent said that washing full loads of clothes was a habit they were likely to adopt to save energy. Turning the thermostat up in the summer was reported by over 54 percent of the respondents and turning the thermostat down in the winter was reported by 58 percent as a habit they and members of the household were most likely to adopt to save energy.

A summary of the survey is included in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

As in previous years, unless directed otherwise, Idaho Power will continue to provide financial assistance to CAP agencies while exploring changes to improve program delivery. The company will continue to provide the most benefit possible to special-needs customers while working with Idaho and Oregon WAP personnel.

Idaho Power will continue to participate in the Idaho and Oregon state monitoring process of weatherized homes and will continue to verify approximately 10 percent of the homes weatherized under the WAQC program via home-verification companies.

In 2019, Idaho Power will support the whole-house philosophy of the WAQC program and Idaho and Oregon WAP by continuing to allow a $6,000 annual maximum average per-home cost.

In Idaho during 2019, Idaho Power expects to contribute the base amount plus available funds from 2018 to total approximately $1,342,900 in weatherization measures and agency administration fees. Of this amount, approximately $86,600 will be provided to the non-profit pooled fund to weatherize buildings housing non-profit agencies that primarily serve qualified customers in Idaho.

Idaho Power will continue to maintain the program on its website and other marketing collateral.

Weatherization Solutions for Eligible Customers

		2018	2017
Participation and Savings			
	Participants (homes)	141	164
	Energy Savings (kWh)	571,741	604,733
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$998,233	$1,137,209
	Oregon Energy Efficiency Rider	$0	$(56,571)*
	Idaho Power Funds	$24,237	$28,224
	Total Program Costs—All Sources	$1,022,471	$1,108,862
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.112	$0.115
	Total Resource Levelized Cost ($/kWh)	$0.112	$0.117
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.37	0.34
	Total Resource Benefit/Cost Ratio	0.51	0.45

*Oregon Rider charges were reversed and charged to the Idaho Rider in February 2017

Description

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers in Idaho whose income falls between 175 percent and 250 percent of the current federal poverty level. Initiated in 2008, the program is designed to mirror the WAQC program. These customers often do not have disposable income to invest in energy efficiency upgrades, and they typically live in housing similar to WAQC customers.

The Weatherization Solutions program also benefits certain customers on the WAQC waiting list. When customer income overlaps both programs, this program may offer an earlier weatherization date than WAQC, resulting in less wait time for the customer and quicker energy savings.

Potential participants are interviewed by a participating contractor to determine household occupant income eligibility, as well as to confirm the home is electrically heated. If the home is a rental, the landlord must agree to maintain the unit's current rent for a minimum of one year, and to help fund a portion of the cost of weatherization. If the customer is eligible, an auditor inspects the home to determine which upgrades will save energy, improve indoor air quality, and/or provide health and safety for the residents. To be approved, energy efficiency measures and repairs must have an SIR of 1.0 or higher, interact with an energy-saving measure, or be necessary for the health and safety of the occupants.

The Weatherization Solutions for Eligible Customers program uses a home audit tool called the HAT14.1 which is similar to the EA5 audit tool used in WAQC. The home is audited for energy efficiency measures, and the auditor proposes upgrades based on the SIR ratio calculated by HAT14.1. As in WAQC, if the SIR is 1.0 or greater, the contractor is authorized to upgrade that measure. Measures considered for improvement are window and door replacement; ceiling, floor, and wall insulation; HVAC repair and replacement; water heater repair and replacement; and pipe wrap. Also included is the potential to replace lightbulbs and refrigerators. Contractors invoice Idaho Power for the project costs, and if the home is a rental, a minimum landlord payment of 10 percent of the cost is required.

Idaho Power's agreement with contractors includes a provision that identifies a maximum annual average cost per home. The intent of the maximum annual average cost is to allow contractors the flexibility to service homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes.

Program Activities

In 2018, contractors weatherized 141 Idaho homes for the program: nine in eastern Idaho by Savings Around Power and Energy Solutions; 60 in Idaho Power's Canyon–West Region by Metro Contractors Services, LLC.; 50 in south-central Idaho by Home Energy Management, LLC (HEM-LLC); and 22 in the company's Capital Region by Power Savers. Of those 141 homes weatherized, 95 were single-family, 42 were manufactured homes, and four were multi-family units.

Marketing Activities

The company used several strategies to reach customers in income-eligible electrically heated homes. In February, a bill insert was sent to 346,672 customers in Idaho and another was mailed to 330,390 in October. The program was promoted at events targeting customers with limited incomes, including seniors. Ads and articles promoted the program in the *Senior BlueBook* in both spring and fall. Letters were mailed to targeted customers in the South-East Region in September (6,156 customers) and to customers in the Capital Region in October (4,938). The program was also highlighted in Idaho Power's November *Connections* newsletter, which is sent to all customers. A *News Scans* article highlighted a Weatherization Solutions customer in July.

Idaho Power ran Facebook ads in March and July 2018 and regular Facebook and Twitter posts in June (Figure 36). The regular posts reached 2,500 people on Facebook, with 21 likes and 4 shares. The March paid ad reached 107,000 people with 357,225 impressions. The July ad reached 95,376 people and had 334,810 impressions. Weatherization tips were also mentioned in various social media posts.

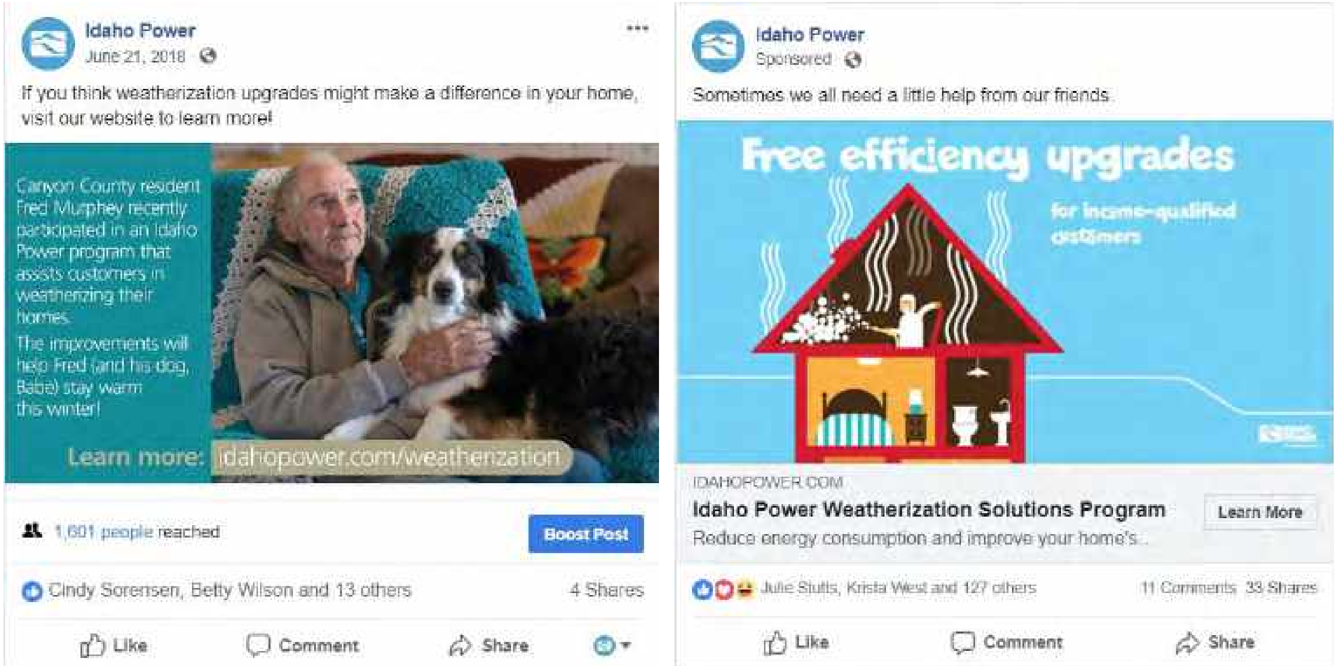


Figure 36. Social media post and paid ad for Weatherization Solutions for Eligible Customers program

Idaho Power's community relations representatives, education representatives, and customer representatives promoted the program at meetings and events in their communities such as American Falls Days. The program specialist and customer representatives promoted the program to home healthcare provider groups, senior groups, and members of the Idaho Nonprofit Center. CAP Agency personnel also promoted the program at community events such as the National Alliance on Mental Illness (NAMI) resource fair and the Treasure Valley Community Resource Fair. Updated brochures (in English and Spanish) that included current income qualifications and location-specific contractor information were used by all. The program was also cross-marketed with other residential energy efficiency programs, such as Home Energy Audit.

Cost-Effectiveness

Benefit-cost ratios increased slightly in 2017. The 2018 utility cost B/C ratio is 0.37, up from 0.34, and the TRC B/C ratio is 0.51 compared with 0.45 in 2017.

Weatherization Solutions for Eligible Customers projects, similar to WAQC program guidelines, benefit from a pre-screening of measures through a home audit process. The home audit process ensures there is an adequate number of kWh savings to justify the project and provides more consistent savings for billing analysis. See WAQC cost-effectiveness for a discussion of the audit and prescreening process, which is similar for both programs. Weatherization solutions savings will be updated in 2019 from the 2015 to 2017 billing analysis as the nearly 1,000 projects will be analyzed jointly to increase sample sizes and provide more robust model estimates.

For further details on the overall program cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction

A customer survey was used to assess major indicators of customer satisfaction with the program throughout the service area. All program participants in all regions were asked to complete a survey after their homes were weatherized. Survey questions gathered the following information: how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely.

Idaho Power received survey results from 109 of 141 households weatherized by the program in 2018. Some highlights include the following:

- Over 24 percent of respondents learned of the program from a friend or relative, and another almost 18 percent learned of the program from an agency flyer. Over 37 percent learned about the weatherization program from direct-mail.
- Over 80 percent of the respondents reported that their primary reason for participating in the weatherization program was to reduce utility bills, and over 29 percent wanted to improve the comfort of their home.
- Over 88 percent reported they learned how air leaks affect energy usage, and nearly 78 percent indicated they learned how insulation affects energy usage.
- Over 65 percent of respondents said they learned how to use energy wisely. Seventy-four percent reported they were very likely to change habits to save energy, and almost 69 percent reported they have shared all of the information about energy use with members of their household.
- Over 84 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost 95 percent said they were very satisfied with the program.
- Over 73 percent of the respondents reported the habit they were most likely to change was turning off lights when not in use, and over 59 percent said that washing full loads of clothes was a habit they were likely to adopt to save energy. Turning the thermostat up in the summer was reported by over 57 percent of the respondents and turning the thermostat down in the winter was reported by nearly 72 percent as a habit they and members of the household were most likely to adopt to save energy.

A summary of the survey is included in *Supplement 2: Evaluation*.

Two independent companies performed random verifications of weatherized homes and visited with customers about the program. In 2018, 22 homes were verified, and 17 (77 percent) of those customers reported they learned “a lot” or “some” about saving electricity in their home. Twenty-one customers (95 percent) reported they had tried “a lot” or “some” different ways to save electricity in their home.

2019 Program and Marketing Strategies

Idaho Power does not anticipate any program operating changes in 2019. Idaho Power will update brochures as necessary to help spread the word about the program in all communities. Additional marketing for the program will include bill inserts and advertisements in various regional publications, particularly those with a senior and low-income focus. Social media ads and boosts will be considered to target specific regions to increase and maintain program awareness. Regional marketing will also be based on need as evidenced by any regional contractor's waiting list for Weatherization Solutions services. The program will again be promoted at county fairs, home shows, and resource fairs, as needed.

Commercial/Industrial Sector Overview

Idaho Power's commercial sector consists of over 71,104 commercial, governmental, school, and small-business customers. In 2018, the number of commercial sector customers increased by 1,254 or 1.8 percent from 2017. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 26 percent of Idaho Power's total electricity sales.

The industrial and special contract customers are Idaho Power's largest individual energy consumers. There are 118 Rate 19 and special contract industrial customers. These customers account for approximately 23 percent of Idaho Power's total electricity sales.

The three C&I Energy Efficiency Program options are available to all commercial, industrial, governmental, schools, and small-business customers. DVL GL conducted a process evaluation for the program in 2017, and the company responded to recommendations in 2018. Also in 2018, the company distributed industry-specific, no-cost ESKs to small commercial customers.

The 2018 season was the fourth year of the internally managed Flex Peak Program, a demand response program designed to reduce the demand on Idaho Power's system during periods of extreme peak electricity use. Program results were slightly reduced from the 2017 season, with a maximum achieved reduction of 33 MW. The program included 65 participants at 140 sites.

Idaho Power also offers the statutory-required Oregon Commercial Audits program to medium and small commercial customers.

Table 16. Commercial/industrial sector program summary, 2018

			Total Cost		Savings	
Program	**Participants**		**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response						
Flex Peak Program	140	sites	$ 433,313	$ 433,313		32.9
Total			**$ 433,313**	**$ 433,313**		**32.9**
Energy Efficiency						
Commercial Energy-Saving Kit	1,652	kits	$ 146,174	$ 146,174	442,170	
Custom Projects	248	projects	8,808,512	16,112,540	46,963,690	
Green Motors—Industrial	25	motor rewinds			64,167	
New Construction	104	projects	2,069,645	5,054,215	13,378,315	
Retrofits	1,358	projects	5,990,179	16,253,716	34,910,707	
Total			**$ 17,014,509**	**$ 37,566,644**	**95,759,049**	

Note: See Appendix 3 for notes on methodology and column definitions.

Marketing

In 2018, Idaho Power continued to market the C&I Energy Efficiency Program as a single entity with incentives for New Construction, Retrofits, Custom Projects, and the new Commercial Energy-Saving Kits, in addition to the company's demand response program, Flex Peak. Marketing activities were targeted toward the following customers: commercial, industrial, governmental, schools, small businesses, architects, engineers, and other design professionals.

Bill Inserts

In March, a bill insert highlighting how Idaho Power's incentives can save customers money was included in 36,782 business customers' bills. A similar bill insert was sent in 36,097 business customers' bills in August to promote the program.

Print Advertising

Idaho Power expanded its ad campaign (Figure 37) for the C&I Energy Efficiency Program, featuring former program participants and iconic local landscapes to capture the readers' attention. The ads targeted small to large businesses and showed that saving energy and money is for everyone.

The ads ran in the *Idaho Business Review* in April, May, August, September, October, and November; the *Business Insider* in January, February, April, May, June, and September; the *BOC Bulletin* in February and August; Alaska Airline's *Horizon Air Magazine* in October; and the *East Idaho Business Journal* in May, September, and November. Ads also ran in the BOMA membership directory and symposium program, Grow Smart Awards event program, *Idaho Business Review* Top Projects Awards publication, and the Idaho Association of General Contractors membership directory. Additionally, Idaho Power sponsored the Construction section in the *Idaho Business Review's Book of Lists*, which included an ad, company logo in the table of contents, and an article highlighting Idaho Power and the company's energy efficiency programs.

Figure 37. Example of C&I Energy Efficiency Program ad

Direct Mail

Idaho Power sent a direct-mailer to 4,335 small-business customers in November informing them of energy-saving programs and encouraging them to contact their customer representative to order a free Commercial ESK for their business. In response to the recommendation for the program's evaluation, Idaho Power tracked the number of calls to customer solutions advisors as a result of the mailing. The letter resulted in 25 customer calls, 12 of which led to a visit by a customer representative.

Newsletters

Idaho Power promotes energy efficiency and its programs through the company's *Energy@Work* newsletter. Written for small- and medium-sized business customers, Idaho Power mailed this newsletter to 23,916 customers in April and 24,140 customers in November 2018. Content included customer success stories and information on the company's training opportunities, energy efficiency tools and programs, energy portfolio, rates, energy advisors, environmental stewardship, customer satisfaction surveys, system reliability, and more.

Idaho Power also sent a quarterly email newsletter, *Energy Insights*, to its large-commercial and industrial customers. Topics included customer success stories, power quality, improving building performance, the benefits of electric forklifts, training opportunities, rate changes, Idaho Power's energy portfolio, how to improve chiller performance, energy-saving maintenance strategies for cooling towers, energy trends, energy management systems, and more.

Print Materials

In 2018, Idaho Power began updating its industry-specific tip brochure to incorporate recommendations from the program's process evaluation to start with the energy-use breakdown for the facility type, focus on the most energy intense systems and how to make them more efficient, and mention NEBs. The company also created a new tip brochure for retail facilities.

Airport Advertising

In 2018, approximately 3.8 million people traveled through the Boise Airport; according to airport officials, half of them are traveling for business. To reach the business customer, Idaho Power placed two backlit display ads throughout the airport in 2018. An ad featuring program participants was located in the baggage claim area, while an ad on alternating airport display boards highlighted that all customers want to save money.

Success Stories

The company released success story videos on YouTube featuring Alpine Automotive, Roaring Springs and Wahooz (Figure 38) and the Pocatello School District. The videos were shared on Idaho Power's social media pages and provided a more in-depth look into the companies' experiences working with Idaho Power, the incentives earned, and the energy savings achieved.

Figure 38. Example of success story videos on Idaho Power's YouTube channel

The *Connections* newsletter shared the energy-saving success story of Holt Arena in January and Alpine Automotive in April.

Digital

New in 2018, Idaho Power ran digital display ads targeting business customers. The ads ran on the *Idaho Statesman* business news pages, blogs, and *Business Insider* web pages from March through May. The ads received 985,065 impressions and 1,343 clicks. The company also used search-engine marketing ads—paid ads that appear in online keyword search results—which received 6,506 impressions and 417 clicks.

The company ran digital ads on the *Idaho Business Review* website, and in their weekly and daily email newsletters throughout the year. These ads received 85,378 impressions and 80 clicks to the Idaho Power Savings For Your Business web page. Idaho Power also placed sponsored content articles on the *Idaho Business Review* website in February and March. These articles are written by Idaho Power and appear as online news stories. The sponsored content articles received 148,514 impressions and 139 clicks. In December, Idaho Power began sponsoring the online Business News section of the *Idaho Business Review* which the company plans to continue in 2019.

Social Media

Idaho Power continued using weekly LinkedIn posts focused on energy-saving tips, program details, incentives, and event information. These posts also highlighted companies who used the program and included photos of large-format check presentations and success story videos. When appropriate, these messages were also shared on Idaho Power's Facebook and Twitter pages.

The company continued using paid LinkedIn ads to promote the C&I Energy Efficiency Program. Idaho Power placed several ads targeted toward a variety of job titles that typically have an interest in or input about energy efficiency projects including C-suite executives; engineers; architects; and sustainability, maintenance, and facilities contacts. Targeting was only available to LinkedIn users in the Boise and Pocatello areas—approximately 93,000 individuals. The ads resulted in 237,402 impressions and 389 website clicks.

Public Relations

Idaho Power provides public relations support to customers who want to publicize the work they have done to become more energy efficient. Upon request, Idaho Power creates large-format checks that are used for media events and/or board meetings. Idaho Power will continue to assist customers with public relations opportunities by creating certificates for display within their buildings and speaking at press events, if requested.

In 2018, Idaho Power produced checks and/or sent news releases for several companies and organizations, including the City of Fruitland, the Nampa School District, the City of Pocatello and Pocatello School District, and SUEZ Water in Boise. SUEZ received an incentive check for $422,083 that will help pay for energy efficiency measures that are saving the water utility more than 2.3 million kWh—enough energy to power about 202 average-sized homes for a year.

Figure 39. Check presentation to SUEZ Water in Boise

As outlined in the Success Stories section above, the public relations team also helped produce a variety of high-quality videos used to promote C&I Energy Efficiency Program across a variety of media.

Association and Event Sponsorships

Idaho Power's C&I Energy Efficiency Program sponsors a number of associations and events, including the Grow Smart awards; Top Projects Awards; BOMA symposium; American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Technical Conference: American Institute of Architects (AIA) Idaho Chapter Design Awards and the U.S. Green Building Council (USGBC).

Idaho Power sponsored the BOMA Commercial Real Estate Symposium February 13, in Boise. The Idaho Power vice president of customer operations and business development spoke about how the company is positioned to support commercial activity with low rates, renewable energy portfolio, high customer satisfaction and reliability, and energy efficiency programs. The company was acknowledged on the AIA Design Awards web page and displayed table tents and brochures throughout the event.

Outreach

Idaho Power reached out to the Idaho Retailers Association and Idaho Restaurant & Lodging Association to inquire about opportunities to share information about the company's C&I Energy Efficiency Program, provide members with industry-specific tip sheets, and promote the Commercial ESKs for Businesses. The company has not received a response from either association.

Customer Satisfaction

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2018, 59 percent of small business survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-four percent of small business respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Fifty-one percent of Idaho Power small-business customers surveyed in 2018 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 28 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

In 2018, 62 percent of large commercial and industrial survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Seventy-six percent of large commercial and industrial respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Seventy-two percent of Idaho Power large commercial and industrial customers surveyed in 2018 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 78 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 93 percent are "very" or "somewhat" satisfied with the program.

Training and Education

In 2018, Idaho Power engineers, program staff, field representatives, and hired consultants continued to provide technical training and education to help customers learn how to identify opportunities to improve energy efficiency in their facilities. The company has found that these activities increase awareness and participation in its energy efficiency and demand response programs and enhance customer satisfaction. To market this service and distribute the training schedule and resources, Idaho Power used its website and *Energy@Work* and *Energy Insights* newsletters. Also, major customer representatives and program energy efficiency engineers emailed training announcements to existing customers.

During each training session, a major customer representative gave an overview of the commercial and industrial programs available to customers. Idaho Power posted prior years' webinar recordings and related files on its Commercial and Industrial Energy Efficiency training web page.

As part of this outreach activity, Idaho Power collaborated with and supported stakeholders and organizations such as: IDL, BOMA, USGBC, ASHRAE, and International Building Operators Association (IBOA). Using Idaho Power funding, the IDL performed several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities included sponsoring a Building Simulation Users Group (BSUG), conducting Lunch & Learn sessions held at various design and engineering firms, and offering a Tool Loan Library (TLL).

Idaho Power delivered 10 technical classroom-based training sessions and two industrial DSM program workshops in 2018 at no cost to the Idaho Power customers. Of the 10 technical sessions, three were two-day classes (one class was presented twice in Boise and Pocatello) and the others were one-day classes. Topics included the following:

- Commercial/Industrial Motor Efficiency (Pocatello)
- Commercial/Industrial Adjustable Speed Drives (Pocatello)
- Compressed Air Challenge Level II—Advanced Management of Compressed Air Systems (Boise)
- Energy Efficiency of Chilled Water Systems (Twin Falls)
- Energy Efficiency of Cooling Towers (Twin Falls)
- Advanced Lighting Control Systems (Boise and Pocatello)
- Energy Efficient Data Center (held live in Boise and video conferenced to Pocatello)
- Industrial Refrigeration Systems Energy Management (Twin Falls)
- HVAC Controls Training (Nampa)
- Optimizing Pumping Systems: A Measurement-Based Approach (Nampa)

The level of participation in 2018 remained high, with 337 attendees for the technical sessions and almost 90 for the program workshops. Customer feedback indicated the average satisfaction level was 94 percent. Idaho Power's average cost to deliver the technical trainings in 2018 was approximately $5,002 per class.

Idaho Power paid at least 50 percent of the cost for Idaho Power customers to take part in IBOA educational classes including the Building Operator Certification (BOC) Level 1 (consisting of eight, day-long classes) and Level 2 (consisting of seven, day-long classes). In 2018, 15 Idaho Power customers attended the Level 1 classes and 10 attended the Level 2 classes.

Field Staff Activities

Idaho Power field staff are on site with customers each day. The field staff uses a variety of Idaho Power-developed programs, tools, and services to help customers with their energy-related questions and challenges. The company sets activity goals for its customer representatives designed to engage customers in the energy efficiency programs such as a specific number of site visits or projects. Additionally, program specialists and engineers work closely with residential and commercial customer representatives to leverage established customer relationships. For example, residential and commercial customer representatives distribute informational materials to trade allies and other market participants who, in turn, support and promote Idaho Power's energy efficiency programs.

Customers regularly ask how to get the most out of their energy dollar. Idaho Power staff has been trained to properly advise customers in the wise use of energy-specific energy efficiency measures and, when needed, can recommend where to find answers. Idaho Power is equipped with experienced engineers, technically proficient personnel, and an extensive network of nationally recognized organizations, contacts at neighboring western electrical utilities, and energy efficiency clearing houses to handle energy-related questions.

Commercial and Industrial Energy Efficiency Program

		2018*	2017
Participation and Savings			
	Participants (projects/kits)	3,387	1,441
	Energy Savings (kWh)**	95,759,049	85,425,027
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source* **			
	Idaho Energy Efficiency Rider	$16,281,639	$14,732,314
	Oregon Energy Efficiency Rider	$720,714	$701,336
	Idaho Power Funds	$12,156	$23,701
	Total Program Costs—All Sources	$17,014,509	$15,457,351
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.015	$0.015
	Total Resource Levelized Cost ($/kWh)	$0.032	$0.032
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.75	3.42
	Total Resource Benefit/Cost Ratio	1.87	1.81

*Metrics for each option (New Construction, Custom Projects, Retrofits, and Commercial ESKs) are reported separately in appendices and in *Supplement 1: Cost-Effectiveness.*

**2018 total includes 64,167 kWh of energy savings from 25 Green Motors projects.

***Dollars include totals for New Construction, Custom Projects, Retrofits, and Commercial ESKs

Description

Three major program options targeting different energy efficiency projects are available to commercial, industrial, governmental, schools, and small-business customers in the company's Idaho and Oregon service areas: Custom Projects, New Construction, and Retrofits. Idaho Power also offers no-cost, industry-specific ESKs filled with items intended to target smaller commercial customers and introduce them to energy-saving measures.

Custom Projects

The Custom Projects option incentivizes energy efficiency modifications for new and existing facilities. The goal is to encourage energy savings in Idaho and Oregon service areas by helping customers implement energy efficiency upgrades. Incentives reduce customers' payback periods for custom modifications that might not be completed otherwise. The Custom Projects option offers an incentive level of 70 percent of the project cost or $0.18 per kWh for first-year estimated savings, whichever is less. The Custom Projects option also offers energy auditing services to help identify and evaluate potential energy-saving modifications or projects.

Interested customers submit a pre-approval application to Idaho Power for potential modifications that have been identified by the customers, Idaho Power, or by a third-party consultant. Idaho Power reviews each application and works with the customer and vendors to gather sufficient information to support the energy-savings calculations.

Once the project is completed, customers submit a payment request; in some cases, large, complex projects may take as long as two years or more to complete. Every payment application is verified by

Idaho Power staff or an Idaho Power contractor. All lighting projects use the Idaho Power Lighting Tool to calculate the annual energy savings and to determine the incentive.

Each project is reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant verifies the energy savings methods and calculations. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, especially the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification (M&V) process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms energy savings are obtained and are within program guidelines. If changes in scope take place in a project, Idaho Power will recalculate energy savings and incentive amounts based on the actual installed equipment and performance.

New Construction

The New Construction option enables customers in Idaho Power's Idaho and Oregon service areas to apply energy-efficient design features and technologies to new construction, expansion, or major remodeling projects. New construction and major renovation project design and construction life is much longer than small retrofits and often encompasses multiple calendar years. Originated in 2004, the option currently offers a menu of measures and incentives for efficient lighting, cooling, building shell, controls, appliances, refrigeration, office equipment, and compressed air options. The customer may otherwise lose savings opportunities for these types of projects.

Thirty-three prescriptive measures are offered for: lighting, HVAC, building shell, controls, appliances with electric water heating, refrigeration, office equipment, and compressed air equipment.

Retrofits

The Retrofits option is Idaho Power's prescriptive measure option for existing facilities. This part of the program encourages customers in Idaho and Oregon to implement energy efficiency upgrades by offering incentives on a defined list of measures. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, food-service equipment, and other commercial measures. Customers can also apply for non-standard lighting incentives. A complete list of the measures offered through Retrofits is included in *Supplement 1: Cost-Effectiveness*.

Commercial Energy-Saving Kits

In 2018, Idaho Power began offering industry-specific Commercial ESKs to its commercial customers in Idaho and Oregon as a means to talk about the benefits of each kit item and other energy efficiency program offerings. Each kit contains installation instructions and a variety of items intended to help save energy related to lighting, hot water use, and intermittently used electrical devices. After talking with customers, the company sends the kits through the mail or an energy advisor delivers the kits to area businesses.

Table 17. Commercial Energy-Saving Kit contents by industry

Restaurant	Retail	Office
(3) 9-watt LED Lightbulbs	(2) 9-watt LED Lightbulbs	(2) 9-watt LED Lightbulbs
(2) Bathroom Aerator 1.0 gpm	(2) 8- watt LED BR30	(2) Bathroom Aerator 1.0 gpm
(2) Kitchen Aerator 1.5 gpm	(1) Bathroom Aerator 1.0 gpm	(1) Kitchen Aerator 1.5 gpm
(2) Exit Sign Retrofit	(2) Exit Sign Retrofit	(2) Exit Sign Retrofit
(1) Pre-rinse Spray Valve		(1) Advanced Power Strip

Program Activities

In 2018, Idaho Power made several improvements to the C&I Energy Efficiency Program in response to recommendations from the 2017 process evaluation by DNV GL. Program-level changes are detailed below; option-level changes are detailed in the subsequent subsections. The complete evaluation report is available in the *Demand-Side Management 2017 Annual Report: Supplement 2, Evaluation*.

After the evaluation, Idaho Power contracted with Tetra Tech to create a formal, written logic model to better understand how specific program activities produce results; this will be incorporated into internal program information.

Idaho Power understands the risks related to program operation and example risk registers identified by the evaluator. Idaho Power plans for these risks by utilizing the Energy Efficiency Potential Study which is forward looking and measures the future energy efficiency that can be targeted. Idaho Power utilizes a third party to create a TRM to evaluate an energy efficiency measure's savings and costs. Idaho Power also utilizes EEAG to help plan future program changes. Through these methods Idaho Power believes future risks will be identified and addressed as they arise.

Each year Idaho Power evaluates and moves measures from the Custom Projects option to the Retrofits or New Construction option for better visibility and customer participation when the average savings has been determined by the RTF or through Idaho Power's TRM. Idaho Power also continues to add new measures as appropriate. The evaluator recommended changing the program design to one that intervened at a different level in the market. Idaho Power feels that changing the design to an upstream model (at the manufacturer's level) or midstream model (at the distributor and installer level) is an entirely different program approach that would be considered if the current approach proves inadequate.

To promote the adoption of efficient technologies to standard practice, as recommended by the evaluator, Idaho Power continued to support the work being done by both the RTF and NEEA in the area of market transformation. New measures are evaluated by Idaho Power annually for program applicability and for cost-effectiveness. Idaho Power also uses a third party to create a TRM that evaluates energy savings and equipment costs. On Custom Projects, Idaho Power determines if measures are standard practice before it calculates savings.

Idaho Power has considered the recommendation to consolidate the internal program manuals. The company determined that the program options require different processes and integrating each of the processes into one program manual has limited benefit to program administration.

Idaho Power has considered consolidating the program tracking files, as recommended, and has determined that the program options require different processes and data; integrating to one program database would require significant effort with limited benefit to program administration and would not lead to any additional actual kWh savings for the program.

Custom Projects

Incentive levels for the non-lighting projects remained the same in 2018, at 18 cents per kWh of first-year savings. Idaho Power reimburses customers up to 70 percent of the project cost.

The Custom Projects option had another successful year with a total of 248 completed projects, 10 of which were in Oregon. Custom Projects achieved energy savings of 46,964 MWh. Energy savings increased in 2018 by nearly 5 percent over 2017. Idaho Power also received 329 new applications representing a potential of 61,251 MWh of savings on future projects.

Over 90 percent of large commercial and industrial customers have participated in the Custom Projects option. With the high percentage of customers who have taken advantage of the program, achieving deeper energy savings continues to be challenging. The company is addressing this ongoing challenge by continuing to use multiple channels to reach customers and to encourage new energy-saving modifications. Table 18 indicates the program's 2018 annual energy savings by primary option measures.

Table 18. Custom Projects annual energy savings by primary option measure, 2018

Option Summary by Measure	Number of Projects	kWh Saved
Retro-commissioning	12	1,062,168
Compressed Air	32	10,468,627
Controls	3	2,663,614
HVAC	3	156,094
Lighting	151	17,131,292
Other	4	339,252
Pump	3	567,331
Refrigeration	10	6,351,813
Variable Frequency Drive (VFD)	30	8,223,499
Total*	**248**	**46,963,690**

*Does not include Green Motor Initiative project counts and savings.

Idaho Power has found providing facility energy auditing, customer technical training, and education services are key to encouraging customers to consider energy efficiency modifications. The 2018 activities not already described in the Commercial and Industrial Sector Overview are below.

Custom Projects engineers and the major customer representatives visited large-commercial and industrial customers to conduct initial facility walk-throughs, commercial/industrial efficiency program informational sessions, and training on specific technical energy-saving opportunities. Idaho Power also hosted a booth at the 2018 Idaho Rural Water Conference. Custom Projects engineers gave presentations on Idaho Power programs and offerings at the 2018 Association of Idaho Cities Annual Conference, the ASHRAE and USGBC Combined Chapter Meeting, the Boise School District Sustainability Summit, the 2018 Idaho Green Building and Energy Conference, and the 2018 Department of Environmental Quality (DEQ) Engineers meeting.

Idaho Power funds the cost of engineering services, up to $4,500, for conducting energy scoping audits to encourage its larger customers to adopt energy efficiency improvements. This was increased from

$3,500 in 2018. Eleven firms contracted to provide scoping audits and general energy efficiency engineering support services. In 2018, an RFP was announced to select a new set of consultants; five firms were selected to provide these services in to 2019.

In 2018, Idaho Power consultants initiated 36 scoping audits and four detailed audits on behalf of Idaho Power customers. These audits identified over 16,300 MWh of savings potential. These audits will be used to promote future projects and will potentially result in energy efficiency projects in the future.

Cohorts and Offerings

The Municipal Water Supply Optimization Cohort (MWSOC), Wastewater Energy Efficiency Cohort (WWEEC), and CEI Cohort for Schools program offerings are also driving a significant number of new projects in addition to increasing vendor engagement from the Streamlined Custom Efficiency (SCE) offering. The company continues to expand the cohort offerings to new customers. In 2018, Custom Projects continued four offerings in an effort to increase the total program savings—WWEEC Continuation, MWSOC, SCE, and the CEI Cohort for Schools—and launched the Eastern Idaho Water Cohort in a joint effort with BPA and Rocky Mountain Power.

Wastewater Energy Efficiency Cohort

In January 2014, Custom Projects launched WWEEC, a cohort training approach for low-cost or no-cost energy improvements for municipal wastewater facilities. WWEEC was a two-year engagement with 11 Idaho Power service area municipalities which continued until 2016. Idaho Power decided to extend the WWEEC to further engaged customers. Seven of the 11 original participants are engaged in the WWEEC Continuation.

Year-three incentives and savings totaled $1,349 and 895,492 kWh/yr. In all cases, the incentive did not exceed 70 percent of the eligible costs. Year-three incentives and savings were processed in 2018. Additionally, some WWEEC participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These capital projects' savings are significant; they are captured separately and recorded as custom projects—not included as WWEEC savings number. In the third year, the consultant contacted participants to check on progress, to discuss opportunities, and to address energy model data updates.

Municipal Water Supply Optimization Cohort

The MWSOC officially launched in January 2016. The goal of the cohort was to equip water professionals with the skills necessary to independently identify and implement energy efficiency opportunities and to ensure that these energy and cost savings are maintained long term.

A final workshop was held in 2018. Participants presented their challenges, successes, and future plans for energy efficiency. Year-one incentives and savings totaled $11,027 and 743,744 kWh/yr with most incentives paid at 70 percent of the eligible cost. Year-one incentives were processed, and savings were reported in 2018. Additionally, some Water Supply Cohort participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These capital projects' savings are significant and recorded as custom projects. The savings are not included as MWSOC savings.

In year-two of the offering, Idaho Power's contractor contacted participants to check on project progress and opportunities and to address energy model data updates. A draft year-two report was created in late 2018 and savings and incentives will be processed in 2019. Due to involvement with the water and wastewater cohort offerings, Custom Projects engineers delivered multiple informational meetings with area civil engineers who specialize in water and wastewater designs to educate them on the C&IE Energy Efficiency Program, the audit process, energy efficiency opportunities, and available tools and resources.

Eastern Idaho Water Cohort

The Eastern Idaho Water Cohort launched in January 2018. The goal of the cohort was to offer the Municipal Water Optimization Supply Cohort to the eastern part of Idaho Power service area. This was accomplished in collaboration with Rocky Mountain Power and BPA to deliver joint workshops for customers located in eastern Idaho. Two Idaho Power customers participated. The first-year savings report is anticipated in 2019.

Continuous Energy Improvement Cohort for Schools

The goal of this cohort is to equip school district personnel with hands-on training and guidance to help them get the most out of their systems while reducing energy consumption. Year-one of The Cohort for Schools ran through the 2017 calendar year. Nine school districts were represented and introduced to the Continuous Energy Improvement (CEI) concepts and planned activities for the cohort. The cohort is implemented by a third-party consultant that provided final M&V reports in early 2018, which resulted in a total energy savings of 1,131,697 kWh/yr for year-one participants.

After year-one reports were reviewed by Idaho Power and incentives paid to the participants, activities were suspended until year-two activities commenced over the summer of 2018. Six participants from year-one continued into the year-two program. Of those six, one district added four new facilities and another district added five new facilities to the program.

Activities in 2018 included opportunity register management for each facility detailing low-cost and no-cost opportunities to reduce energy consumption based on site visits. The consultant worked with each participant to complete as many opportunity register items as possible. The consultant conducted a monthly check-in and coaching call for each school district to review opportunity register items and to discuss their current activities. Scoping audits were initiated by Idaho Power for each new facility that was added to the program, which will identify capital project opportunities, in addition to the low-cost measures being implemented via the cohort, to help aid in the strategic capital planning process. Idaho Power provided program and incentive information, along with numerous other energy-saving resources pertinent to school facilities, in hard copy and on flash drive to each school district.

Year-two activities will continue until May 31, 2019. Then, Idaho Power will review final M&V reports to establish energy savings and eligible costs for year two and to distribute the corresponding incentives to participating school districts.

Streamlined Custom Efficiency

Started in 2013, the SCE offering continues to keep vendor engagement high. The SCE offering provides custom incentives for small compressed-air system improvements, fast-acting doors in

cold-storage spaces, refrigeration controllers for walk-in coolers, and process-related VFDs.
This offering targets projects that may have typically been too small to participate in the Custom Projects option due to the resources required to adequately determine measure savings. Idaho Power contracted with a third party to manage SCE data collection and analysis for each project. In 2018, the SCE offering processed 48 projects, totaling 4,193,931 kWh of savings and $562,745 in incentives.

In August 2018, the fast-acting doors and small compressed air measures were moved out of SCE to prescriptive Retrofits and New Construction offerings because Idaho Power had developed a good understanding of the appropriate energy savings, projects costs, and incentives for these types of projects based on SCE experience. The consultant managing SCE will continue to support vendors and customers working with these measures to ensure the correct incentive paperwork and supporting information is submitted to the prescriptive programs.

Custom Efficiency Process Improvements

In 2018, Idaho Power responded to the three recommendations for the Custom Projects option from the 2017 evaluation; all were related to the database where Idaho Power enters customer information. Idaho Power chose not to implement the evaluator’s suggestion to store one type of information in each column/variable or to create new variables. It is common for Idaho Power to have the customer’s pre- and post-kWh usage for a project, but when that data is unavailable, the company populates the kWh savings in the “kWh before variable” and a zero in the “kWh after variable.” The kWh savings are the data that the company is interested in for reporting and recording the data this way provides the same results. The company revised the publicly available option manual to clarify this practice.

The company did adopt the other two recommendations to adjust the database output report. Idaho Power renamed the column/variable titles to clarify the measure and began filling in measure data in chronological order to ensure information is populated in the correct columns.

New Construction

In 2018, 104 projects were completed, resulting in 13,378,315 kWh in energy savings in Idaho and Oregon.

Maintaining a consistent offering is important for large projects with long construction periods, however, changes are made to enhance customers’ choices or to meet new code changes. Idaho Power tries to keep the New Construction option consistent by making changes approximately every other year. Idaho Power performed a review of the New Construction measures in 2018 based on the 2015 International Energy Conservation Code (IECC) information updated in the TRM. This review resulted in the addition or modification of several measures and the removal of the evaporative pre-coolers on air cooled condenser measure because it was not cost-effective.

These measures were continued in 2018:

- Exterior lighting
- Daylight photo controls
- Occupancy sensors
- Direct evaporative coolers

- Reflective roof treatment
- HVAC variable-speed drives
- Kitchen hood variable-speed drives
- Onion/potato shed ventilation variable-speed drives
- Efficient laundry machines
- ENERGY STAR® under-counter dishwashers
- ENERGY STAR® commercial dishwashers
- Refrigeration head-pressure controls
- Refrigeration floating-suction controls
- Efficient condensers
- Smart power strips

These measures were added:

- High-volume low-speed fans
- Diary vacuum pump variable speed drives
- Wall/engine block heater controls
- Refrigerator/freezer strip curtains
- Automatic high-speed doors
- Air compressor variable speed drives
- No-loss condensate drain
- Low-pressure drop filters
- Cycling refrigerated compressed air dryers
- Efficiency compressed air nozzles

The following measures were modified due to small clarification issues or changes in measure cost, cost-effectiveness, or code baseline updates:

- Interior lighting
- High-efficiency exit signs
- Efficient A/C and heat pump units
- Efficient variable refrigerant flow units
- Efficient chillers
- Air side economizers

- Energy-management HVAC control systems
- Guest room energy-management HVAC systems

The Professional Assistance Incentive is an incentive given to architects and/or engineers for supporting technical aspects and documentation of the project. It is equal to 10 percent of the participant's total incentive, up to a maximum amount of $2,500. In 2018, 44 projects received this incentive compared to 39 projects in 2017, and 30 projects in 2016.

Idaho Power representatives visited nine architectural and engineering firms in Boise and Pocatello, and four organizations and municipalities in Boise in 2018. Representatives visited with 134 professionals to build relationships with the local design community, and to discuss Idaho Power's C&I Energy Efficiency program.

The New Construction option continued random installation verification on 10 percent of projects in 2018. The purpose of the verifications is to confirm program guidelines and requirements are adequate and to ensure participants are able to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 12 of the 104 projects, which encompass over 11.5 percent of the total completed projects in the program. Out of the 12 projects verified, only one project verification identified a discrepancy. Idaho Power will review the discrepancy to determine if clarification of program requirements is needed or additional information is required from participants.

In 2018, Idaho Power responded to the two recommendations for the New Construction option from the 2017 evaluation. The company did not adopt the recommendation to eliminate empty cells in the database because the data provided in the application is transferred electronically into a tracking system. The placement of each value is specific to a field in the tracking system. Empty cells are common for measures the participant is not applying for and are required for the proper transfer of data from the application to the tracking system. Idaho Power updated the online application with instructional text based on the evaluator's second recommendation. For example, Idaho Power added mouse-over text to entry cells on the HVAC tab to inform participants of the acceptable size range of units that are eligible for a specific incentive. Idaho Power will continue to make improvements as the applications are updated and modified.

Retrofits

The Retrofits option experienced high participation and energy savings in 2018. Once again, lighting retrofits comprised the majority of the projects.

Idaho Power performed a review of the Retrofits lighting and non-lighting measures. This review resulted in removing some measures from the program due to cost-effectiveness, modifying some measures, and adding new measures to the incentive menu.

Idaho Power facilitated seven program update workshops across its service area targeting electrical contractors, electrical suppliers and large customers, with 143 in attendance. To help contractors understand advanced lighting controls, and in preparation for rolling out Retrofits program changes mid-year, Idaho Power hosted two hands-on technical Advanced Lighting Controls classes with 43 electricians and large customers in attendance. The class was an updated version of the pilot course Idaho Power hosted in 2017. The courses were offered by the DesignLights Consortium (DLC), and NEEA contributed funds through its Luminaire Level Lighting Controls (LLLC) Initiative. Attendees provided positive feedback and indicated they would like additional training in the area of advanced lighting controls.

Idaho Power staff and contractors continued to work with electrical contractors and electrical equipment suppliers across its service area to respond to inquiries, strengthen relationships, encourage participation, increase knowledge of the incentives, and receive feedback about the market and individual experiences. As Idaho Power staff developed program changes, they contacted various contractors and suppliers for their opinions and feedback to aid in program design.

Idaho Power continued its contracts with Evergreen Consulting Group, LLC; Honeywell, Inc.; and RM Energy Consulting to provide ongoing program support for lighting and non-lighting reviews and inspections, as well as contractor outreach. The Honeywell contract expired at the end of 2018, and Idaho Power retained KW Engineering to replace Honeywell in support of the Retrofits non-lighting project reviews and inspections.

In 2018, Idaho Power responded to the two recommendations for the Retrofits option from the 2017 evaluation. The company is investigating the first recommendation to minimize manual data entry when transferring information from non-lighting project application forms to the program's database, similar to the process used for lighting projects where the data is electronically uploaded to the program database.

To address the second recommendation to improve the application forms, Idaho Power added text to the Lighting Tool Welcome tab to direct the applicant to complete the information in the white cells and to notify them that the blue cells would automatically populate. The company also added written instruction for entering information in the Lighting Operation Schedule section. To eliminate confusion, the company spelled out acronyms throughout the Lighting Tool.

Commercial Energy-Saving Kits

Idaho Power distributed more than 1,600 kits to its commercial customers. Nearly 80 percent of the kit distribution was initiated after a customer spoke with a company representative over the phone.

Table 19. Kit distribution and savings by kit type and state, 2018.

State	Kit Type	Total Distributed	kWh Savings
Idaho	Restaurant	264	187,477
	Retail	155	37,288
	Office	1,202	209,196
Oregon	Restaurant	5	3,550
	Retail	2	481
	Office	24	4,177

Marketing Activities

Since combining the separate commercial and industrial programs into this larger, simplified program, Idaho Power has continued to market the C&I Energy Efficiency Program options to contractors, customers, and professional consultants. See the Sector Overview for the company's efforts to market the C&I Energy Efficiency Program as a single offering.

In response to the 2017 program process evaluation, the company is continuing to update its materials to add more appealing content. The company made the success story videos available on the C&I Energy Efficiency Program web pages and increased its use of customer testimonials and stories in its advertising campaign and elsewhere, when appropriate. Idaho Power also updated its C&I Energy Efficiency slide deck to outline the incentives available and incorporate customer stories. The company continues to use energy efficiency program marketing to enhance Idaho Power's image by informing customers of the programs during high bill calls, explaining why the company encourages energy efficiency and what some of the NEBs are, sharing tips and program information in the *Connections* newsletter, participating in community events when relevant, and more.

Below are the option-specific marketing efforts for 2018.

Custom Projects

In addition to promotion activities mentioned above, Idaho Power produced large-format checks and sent news releases for media events, city council meetings, and/or board meetings.

New Construction

In September, Idaho Power updated its New Construction brochure to incorporate the program changes implemented in August. The company mailed out the brochure along with a letter promoting the New Construction offering to 243 architects and engineers in October.

Idaho Power also began placing banners (Figure 40) on select construction sites highlighting that the facility is being built or enhanced with energy efficiency in mind. Banners were placed at Wilson Elementary in Caldwell and Peace Valley Charter School in Boise.

Figure 40. Idaho Power banner displayed at Wilson Elementary, Caldwell

Retrofits

Idaho Power sent a direct-mail to 23,700 business customers in February highlighting the Retrofits option and informing customers of the New Construction and Custom Project incentives. The direct-mail makes customers aware of the company's energy-saving opportunities and encourages them to contact their customer representative to learn more.

Commercial Energy-Saving Kits

When Idaho Power launched the Commercial ESKs, it intended to use them as a tool for customer representatives to communicate with small businesses. Idaho Power ran a small commercial customer campaign offering direct-mailed kits, created a promotional flyer and web page, sent a press release to media, and mailed a letter to small-business customers.

Cost-Effectiveness

Custom Projects

All projects submitted through the Custom Projects option must meet cost-effectiveness requirements, which include TRC, UCT, and PCT tests from a project perspective. The program requires all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As a project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used to provide a scoping audit, a detailed audit, or engineering measurement and verification services available under the Custom Projects option.

The UCT and TRC ratios for the program are 3.85 and 2.32 respectively. An impact evaluation was conducted for the program in 2018. If the amount incurred for the 2018 evaluation was removed from the program's cost-effectiveness, the UCT would be 3.87 while the TRC would remain unchanged at 2.32.

Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

New Construction

To calculate energy savings for the New Construction option, Idaho Power verifies the incremental efficiency of each measure over a code or standard practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters, including the efficiency of the installed measure compared to code-related efficiency. Another method for calculating savings is based on industry standard assumptions, when precise measurements are unavailable. Since the New Construction option is prescriptive and the measures are installed in new buildings, there are no baselines of previous measurable kWh usage in the building. Therefore, Idaho Power uses industry standard assumptions from the IECC to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

New Construction incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kW reduction.

Based on the current deemed savings value from the TRM, nearly all measures were cost-effective, with the exception of some A/C units and heat pump units. Idaho Power determined these measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power had received a cost-effectiveness exception on these measures when it filed changes to the program in 2018 under Advice No. 18-08.

To prepare for 2018 program changes, ADM, under contract with Idaho Power, updated the TRM for the New Construction option in 2018. The TRM, which provides savings and costs related to existing and new measures for the New Construction option, will be updated to include the IECC 2015 baseline.

The new savings will be reflected on all applications initiated after the August 2018 program update.

Complete updated measure-level details for cost-effectiveness can be found in the 2018 *Supplement 1: Cost-Effectiveness*. Assumptions for measures prior to the mid-year update can be found in the *Demand-Side Management 2017 Annual Report, Supplement 1: Cost-Effectiveness.*

Retrofits

For the majority of 2018, Idaho Power used most of the same savings and assumptions as were used in 2017 for the Retrofits option. For all lighting measures, Idaho Power uses a Lighting Tool developed by Evergreen Consulting, Group LLC. An initial analysis was conducted to see if the lighting measures shown in the tool were cost-effective based on the average input of watts and hours of operation, while the actual savings for each project are calculated based on specific information regarding the existing and replacement fixture. For most non-lighting measures, deemed savings from the TRM or RTF are used to calculate the cost-effectiveness. To prepare for 2018 program changes, ADM, under contract with Idaho Power, updated the TRM for the Retrofits option. The TRM provides savings and costs related to existing and new measures for the Retrofits option. The new savings will be reflected on all applications submitted after the August 2018 program update.

Several measures that are not cost-effective remain in the program. These measures include high-efficiency A/C units and heat pump units. After reviewing these measures, Idaho Power determined the measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These cost-effectiveness exceptions were approved by the OPUC in Advice No. 18-08.

Complete updated measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*. Assumptions for measures prior to the mid-year update can be found in *the Demand-Side Management 2017 Annual Report, Supplement 1: Cost-Effectiveness.*

Evaluations

In 2018, Tetra Tech MA (Tetra Tech) was retained to conduct an impact evaluation for the Custom Projects option of the C&I Energy Efficiency Program and found an overall realization rate of 100.4 percent.

The results revealed a successfully run program with only minor savings adjustments made mainly due to changes to customer operation after equipment installation. Overall, findings from the impact evaluation show the program savings calculations were reasonable, had accurate equipment descriptions, well substantiated and conservative assumptions, and technically correct calculations for most of the evaluated projects.

Idaho Power will consider any recommendations from this evaluation in 2019. See the complete impact evaluation report in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

Idaho Power will expand its promotion of the C&I Energy Efficiency Program to additional online and print business publications. The three options will continue to be marketed as part of Idaho Power's C&I Energy Efficiency Program. Below are specific strategies that apply to the individual components of the program for 2019.

Custom Projects

Over the years, the Custom Projects option has achieved a high service-area penetration rate. As stated previously, more than 90 percent of the large-power service customers have participated in the Custom Projects option. The company is actively working to support these customers in new ways and find additional opportunities for cost-effective energy-saving projects.

Additional program offerings are currently under consideration for implementation in 2019, including an SEM Continuation of Services offering for MWSOC participants who are interested in continuing their success, or have improved their readiness for SEM engagement.

Activities and coaching will continue for the WWEEC continuation participants and the Eastern Idaho Water Cohort. Idaho Power is also investigating details related to continuation and/or expansion of the CEI Cohort for Schools offering beyond the year-two completion scheduled for summer of 2019.

Idaho Power will continue to provide site visits by Custom Projects engineers and energy scoping audits for project identification and energy-savings opportunities; M&V of larger, complex projects; technical training for customers; and funding for detailed energy audits for larger, complex projects.

New Construction

Idaho Power will continue to perform random post-project verifications on a minimum of 10 percent of completed projects, sponsor technical training through the IDL to address the energy efficiency education needs of design professionals throughout the Idaho Power service area, and build relationships with local design professionals and organizations.

Retrofits

Idaho Power will coordinate with NEEA and the Lighting Design Lab (LDL) to offer an advanced lighting controls class to lighting contractors.

Commercial Energy-Saving Kits

In 2019, Idaho Power will continue sending these kits to commercial customers upon request. The company will consider more actively marketing the kits to customers through various methods including social media and direct-mail.

Flex Peak Program

	2018	2017
Participation and Savings		
Participants (sites)	140	141
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	33	36
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$58,727	$86,861
Oregon Energy Efficiency Rider	$64,316	$231,285
Idaho Power Funds	$310,270	$340,010
Total Program Costs—All Sources	$433,313	$658,156
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a

Description

The Flex Peak Program is a voluntary program where participants are eligible to earn a financial incentive for reducing load. The program is available to Idaho and Oregon commercial and industrial customers with the objective to reduce the demand on Idaho Power's system during periods of extreme peak electricity use.

These are the program event guidelines:

- June 15 to August 15 (excluding weekends and July 4)
- Up to four hours per day between 2:00 p.m. and 8:00 p.m.
- Up to 15 hours per week
- No more than 60 hours per season
- At least three events per season

Customers with the ability to offer load reduction of at least 20 kW are eligible to enroll in the program. The 20-kW threshold allows a broad range of customers to participate in the program. Participants receive notification of a load reduction event two hours prior to the start of the event.

The program originated in 2009 as the FlexPeak Management program managed by a third-party contractor. In 2015, Idaho Power took over full administration, and changed the name to Flex Peak Program. The IPUC issued Order No. 33292 on May 7, 2015, while the OPUC approved Advice No. 15-03 on May 1, 2015, authorizing Idaho Power to implement an internally managed Flex Peak Program (Schedule No. 82 in Idaho and Schedule No. 76 in Oregon) and to continue recovering its demand response program costs in the previous manner.

Program Activities

In 2018, 65 participants enrolled 140 sites in the program—five of those sites were new. Existing customers were automatically re-enrolled in the program. Participants had a committed load reduction of 29.4 MW in the first week of the program and ended the season with an amount of 29.6 MW. This weekly commitment, or nomination, was comprised of all 140 sites. The maximum realization rate during the season was 108 percent, and the average for the three events was 89 percent. This is an overall increase from 81 percent in 2017. The realization rate is the percentage of load reduction achieved versus the amount of load reduction committed for an event. The highest hourly load reduction achieved was 33 MW (at generation level) during the July 31 event (Table 20).

Table 20. Flex Peak Program demand response event details

Event Details	Monday, July 16	Wednesday, July 25	Tuesday, July 31
Event time	4–8 p.m.	4–8 p.m.	4–8 p.m.
Average temperature	93°F	98°F	96°F
Maximum load reduction (MW)	27	22	33

Marketing Activities

The Flex Peak Program continued to be included along with the C&I Energy Efficiency Program collateral. Additional details can be found in the Commercial/Industrial Sector Overview.

Customer representatives conducted field visits with 2017 participants in the offseason and early spring to ensure re-enrollment was successful; verify load size, load traits, and type of operation; and to communicate available incentive amounts based on customer load size.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for its demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2017.

The Flex Peak Program was dispatched for 12 event hours and achieved a maximum reduction of 29.1 MW. The total cost of the program in 2018 was $433,313. Had the Flex Peak Program been used for the full 60 hours, the cost would have been approximately $703,000.

A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-Effectiveness.*

Evaluations

As required each year by IPUC and OPUC, Idaho Power conducted an internal evaluation of the program's potential load reduction impacts. The goal of the review was to calculate the load reduction in MW for the program. The analysis also verified load reduction per site and per event. A copy of the results of this study is in *Supplement 2: Evaluation*.

2019 Program and Marketing Strategies

The company will continue to communicate the value proposition with enrolled customers and the importance of active participation when events are called. Idaho Power will meet with existing participants during the off-season to discuss past-season performance and upcoming season details.

For the upcoming season, Idaho Power will update the program brochure to match the look and feel of other C&I Energy Efficiency Program materials. Though the terms of IPUC Order No. 32923 and OPUC Order No. 13-482 do not require program marketing, Idaho Power customer representatives regularly communicate with current participants and encourage them to enroll new sites. Idaho Power will promote the program along with Idaho Power's C&I Energy Efficiency Program, when applicable.

Oregon Commercial Audits

		2018	2017
Participation and Savings			
	Participants (audits)	0	13
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$1,473	$8,102
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$1,473	$8,102
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Oregon Commercial Audits identifies opportunities for all commercial and industrial building owners, governmental agencies, schools, and small businesses to achieve energy savings. Initiated in 1983, this statutory required program (ORS 469.865) is offered under Oregon Tariff Schedule No. 82.

Through this program, Idaho Power provides free energy audits, evaluations, and educational products to customers through a third-party contractor. During the audits, the contractor inspects the building shell, HVAC equipment, lighting systems, and operating schedules, if available, and reviews past billing data. These visits provide a venue for contractor to discuss available incentives and specific business operating practices for energy savings. The contractor may also distribute energy efficiency program information and remind customers that Idaho Power personnel can offer additional energy-savings tips and information. Business owners can decide to change operating practices or make capital improvements designed to use energy wisely.

Program Activities

During 2018, no customers requested audits through this program. As in 2017, EnerTech Services was available to conduct the audits, and Idaho Power personnel were available to assist customers.

The 2018 program costs were lower than 2017 because the contractor did not perform any audits.

Marketing Activities

Idaho Power sent its annual direct-mailing to 1,520 Oregon commercial customers in September to explain the program’s no-cost or low-cost energy audits and the available incentives and resources.

Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82, the Commercial Energy Conservation Services Program. Because the required parameters of the Oregon Commercial Audit program are specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost-effective. Idaho Power claims no energy savings from this program.

2019 Program and Marketing Strategies

Idaho Power does not expect to make any operational changes to the program in 2019.

Idaho Power will continue to market the program through the annual customer notification and will consider additional opportunities to promote the program to eligible customers.

Irrigation Sector Overview

The irrigation sector is comprised of agricultural customers operating water-pumping or water-delivery systems to irrigate agricultural crops or pasturage. End-use electrical equipment primarily consists of agricultural irrigation pumps and center pivots. The irrigation sector does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2018, the active and inactive irrigation service locations totaled 20,077 system-wide. This was an increase of 1.5 percent compared to 2017, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow or surface irrigated to sprinkler irrigation. Irrigation customers accounted for 1,976,587 MWh of energy usage in 2018, which was an increase from 2017 of approximately 12 percent, primarily due to variations in weather. This sector represented nearly 14 percent of Idaho Power's total electricity sales, and approximately 29 percent of July sales. Energy usage for this sector has not changed significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector:

1. Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components.
2. Irrigation Peak Rewards, a demand response program designed to provide a system peak resource.

The Irrigation Efficiency Rewards program, including the Green Motor Initiative, experienced increased annual savings, from 16,888 MWh in 2017 to 19,002 MWh in 2018.

Idaho Power recruited the majority of 2017 Irrigation Peak Rewards participants in 2018, with an increase of 1.7 percent in eligible service points.

Table 21 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

Table 21. Irrigation sector program summary, 2018

		Total Cost		Savings	
Program	**Participants**	**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response					
Irrigation Peak Rewards	2,335 service points	$ 6,891,737	$ 6,891,737		297
Total		**$ 6,891,737**	**$ 6,891,737**		**297**
Energy Efficiency					
Irrigation Efficiency Rewards	1,022 projects	$ 2,953,706	$11,948,469	18,933,831	
Green Motors—Irrigation	26 motor rewinds			67,676	
Total		**$ 2,953,706**	**$11,948,469**	**19,001,507**	

Note: See Appendix 3 for notes on methodology and column definitions.

Marketing

In 2018, the company mailed a spring and fall edition of *Irrigation News* to all irrigation customers in its service area. The spring edition focused on Idaho Power's efforts to improve irrigation customer satisfaction, rate changes, rewards for custom projects, and contact information for regional agriculture representatives. Two versions of the spring newsletter were created to cater to the differences in rate changes for Oregon and Idaho customers. The fall edition again noted customer satisfaction efforts and featured information on online tools for account management and outages, a 2019 calendar of events for agriculture shows, energy efficiency incentives, and Idaho Power's overhead power line safety video specifically made for the irrigation community. This newsletter provides an opportunity to increase transparency and trust and to promote the Irrigation Efficiency Rewards program.

Throughout 2018, changes to program brochures, project applications, and other marketing collateral made the materials more consistent with each other and other Idaho Power publications.

The company also placed numerous ads in print agricultural publications to reach the target market in smaller farming communities. Publications included: *Capital Press*, *Gem State Producer*, *Times–News*, *Owyhee Avalanche*, *Idaho Press*, *Power County Press*, *Potato Grower Magazine*, *Idaho Cattle Association Guide*, *Malheur Enterprise*, and *Post Register*. Idaho Power utilized radio advertising to promote its presence at the Agri-Action show and to show support of Future Farmers of America and Ag Week conferences.

In spring 2018, Idaho Power partnered once again with the Twin Falls County Pest Abatement District to promote irrigation equipment efficiency while educating the public on mosquito abatement—preventing large pools of water where mosquitoes breed. The promotion ran as a commercial on KMVT and through digital ads in the Twin Falls area March through April. Digital advertising was used to drive traffic to the Irrigation Efficiency web page; the click-through rate was 0.14 percent—well above the industry average of 0.08 percent.

Customer Satisfaction

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2018, 61 percent of irrigation survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Seventy percent of irrigation respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Fifty-six percent of Idaho Power irrigation customers surveyed in 2018 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 37 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 91 percent are "very" or "somewhat" satisfied with the program.

Training and Education

Idaho Power continued to market its irrigation programs by varying the location of workshops and offering new presentations to irrigation customers. In 2018, Idaho Power provided eight workshops promoting the Irrigation Efficiency Rewards program. Approximately 200 customers attended workshops in Vale, Oregon and Aberdeen, Mountain Home, Nampa, Eagle, Burley, Leadore, and Emmett, Idaho. The company displayed exhibits at regional agricultural trade shows, including the Idaho Irrigation Equipment Association Winter Show, Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show, and the Treasure Valley Irrigation Conference.

Field Staff Activities

Idaho Power's agricultural representatives offer customer education, training, and irrigation-system assessments and audits across the service area. Agricultural representatives also engage agricultural irrigation equipment dealers in training sessions with the goal of sharing expertise about energy-efficient system designs and increasing awareness about the program. Agricultural representatives and the irrigation segment coordinator, a licensed agricultural engineer, participate in annual training to maintain or obtain their Certified Irrigation Designer and Certified Agricultural Irrigation Specialist accreditation. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Irrigation Efficiency Rewards

		2018	2017
Participation and Savings			
	Participants (projects)	1,048	801
	Energy Savings (kWh)*	19,001,507	16,888,049
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$2,681,664	$2,230,798
	Oregon Energy Efficiency Rider	$233,916	$192,416
	Idaho Power Funds	$38,126	$52,463
	Total Program Costs—All Sources	$2,953,706	$2,475,677
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.019	$0.018
	Total Resource Levelized Cost ($/kWh)	$0.075	$0.060
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.57	4.75
	Total Resource Benefit/Cost Ratio	3.03	3.64

*2018 total includes 67,676 kWh of energy savings from 26 Green Motors projects

Description

Initiated in 2003, the Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's service areas can receive financial incentives and reduce their electricity usage through participation in the program. Two options help meet the needs for major or minor changes to new or existing systems: Custom Incentive and Menu Incentive.

Custom Incentive Option

The Custom Incentive Option is offered for extensive retrofits to existing systems or the installation of an efficient, new irrigation system.

For a new system, Idaho Power determines whether the equipment is more energy efficient than standard before approving the incentive. If an existing irrigation system is changed to a new water source, this program considers it a new irrigation system. The incentive for a new system is 25 cents per annual kWh saved, not to exceed 10 percent of the project cost.

For existing system upgrades, the incentive is 25 cents per annual kWh saved or $450 per kW demand reduction, whichever is greater. The incentive is limited to 75 percent of the total project cost.

The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh use of an irrigation system or that result in a potential demand reduction. Idaho Power reviews, analyzes, and makes recommendations on each project after considering prior usage history, invoices, and, in most situations, post-installation demand data to verify savings and incentives.

Menu Incentive Option

The Menu Incentive Option covers a portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems where small maintenance upgrades provide energy savings from these 11 separate measures:

- New flow-control type nozzles
- New nozzles for impact, rotating, or fixed-head sprinklers
- New or rebuilt impact or rotating type sprinklers
- New or rebuilt wheel-line levelers
- New complete low-pressure pivot package
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand-lines, wheel-lines, and portable mainlines
- New wheel-line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on a predetermined kWh savings per component.

Program Activities

In 2018, 1,022 irrigation efficiency projects were completed as follows: 843 utilized the Menu Incentive Option and provided an estimated 12,170 MWh of energy savings and 23.8 MW of demand reduction; 179 utilized the Custom Incentive Option (82 were new systems and 97 were on existing systems) and provided 6,987 MWh of energy savings.

Marketing Activities

In addition to training and education activities mentioned in the Irrigation Sector Overview, Idaho Power targeted a select number of nonparticipants to increase program awareness. Idaho Power maintained a database of irrigation dealers and vendors for direct-mail communication, as they are key to the successful marketing of the program.

Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements under the Custom Incentive Option and the Menu Incentive Option of Irrigation Efficiency Rewards.

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer’s participation in the program. On existing system upgrades, Idaho Power calculates the savings of a project by determining what changes are made and comparing it to the service point’s previous five years of electricity usage history on a case-by-case basis. On new system installations, the company uses standard practices as the baseline and determines the efficiency of the applicant's proposed project. Based on the specific equipment to be installed, the company calculates the estimated post-installation energy consumption of the system. The company verifies the completion of the system design through aerial photographs, maps, and field visits to ensure the irrigation system is installed and used in the manner the applicant's documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure deemed savings are appropriate and reasonable. Payments are calculated on a prescribed basis by measure. In some cases, the energy-savings estimates in the Menu Incentive Option are adjusted downward from deemed RTF savings to better reflect known information on how the components are actually being used. For example, a half-circle rotation center pivot will only save half as much energy per sprinkler head as a full-circle rotation center pivot. All deemed savings are based on seasonal operating hour assumptions by region. If a system's usage history indicates it has lower operating hours than the assumptions, like the example above, the deemed savings are adjusted.

In March 2018, the RTF updated the irrigation hardware measure analysis, which resulted in a reduction of savings between 34 to 94 percent from the previous workbook. The major assumption driving the measure savings change in the program involves the calculation of the leakage per hardware item, which caused savings to decrease nearly 80 percent on average for several irrigation hardware types. Idaho Power has requested the RTF reconvene the irrigation subcommittee in 2019 and re-examine the assumptions such as leakage and flow rate, as well as the calculation methodology behind these irrigation measure. In the meantime, the company plans to use the current workbook for 2019. However, if the RTF approves a new workbook in 2019, Idaho Power will reevaluate and may retroactively apply those updated savings for 2019.

Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

2019 Program and Marketing Strategies

Idaho Power does not expect to make any changes to the Custom Incentive Option in 2019. However, the company will be adjusting Menu Option savings due to new savings numbers being created by the RTF. Idaho Power will also initiate work with the RTF and regional irrigation experts to review the RTF savings adjustments to determine if additional research or information is needed to improve accuracy of savings calculations.

Marketing plans include conducting at least six customer-based irrigation workshops to promote energy efficiency technical education as well as program specifics. Idaho Power will continue to participate in three regional agricultural trade shows, in addition to sponsoring the Idaho Irrigation Equipment Association Show & Conference and the Soil Health Symposium. Marketing the program to irrigation vendors will continue to be a priority. Idaho Power will continue to promote the program in agriculturally focused editions of newspapers and magazines, and to provide valuable information in its *Irrigation News* newsletter.

Irrigation Peak Rewards

		2018	2017
Participation and Savings			
	Participants (participants)	2,335	2,307
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	297	318
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$230,953	$743,948
	Oregon Energy Efficiency Rider	$180,865	$205,528
	Idaho Power Funds	$6,479,919	$6,273,625
	Total Program Costs—All Sources	$6,891,737	$7,223,101
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Idaho Power's Irrigation Peak Rewards program is a voluntary, demand response program available to agricultural irrigation customers with metered service locations who have participated in the past. Initiated in 2004, the purpose of the program is to minimize or delay the need to build new supply-side resources.

The program pays irrigation customers a financial incentive to interrupt the operation of specific irrigation pumps using of one or more control devices. Historically, the Irrigation Peak Rewards program provides approximately 320 MW, or nearly 9 percent of Idaho Power's all-time system peak of load reduction.

The program offers two interruption options: Automatic Dispatch Option and Manual Dispatch Option. Automatic Dispatch Option pumps are controlled by an Advanced Metering Infrastructure (AMI) or a cellular device that remotely turns off the pump(s). Manual Dispatch Option pumps can participate if they have 1,000 cumulative horsepower (hp) or the AMI or cellular technology has been determined to not function properly. These customers nominate a kW reduction and are compensated based on the actual load reduction during the event.

For either interruption option, these are the program event guidelines:

- June 15 to August 15 (excluding Sundays and July 4)
- Up to four hours per day between 1:00 p.m. and 9:00 p.m.
- Up to 15 hours per week

- No more than 60 hours per season
- At least three events per season

The incentive structure consists of fixed and variable payments. The fixed incentive is $5.00/kW with an energy credit of $0.0076/kWh. The demand (kW) credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount. The energy (kWh) credit is calculated by multiplying the monthly billing kWh usage by the energy-related incentive amount. The incentive is applied to monthly bills, and credits are prorated for periods when reading/billing cycles do not align with the program season dates. An additional variable credit of $0.148/kWh applies to the fourth and subsequent events that occur between 1:00 p.m. and 8:00 p.m. and is increased to $0.198/kWh when customers allow Idaho Power to interrupt their pumps until 9:00 p.m.

Program rules allow customers the ability to opt out of dispatch events up to five times per service point. The first three opt outs each incur a penalty of $5 per kW, while the remaining two incur a penalty of $1 per kW based on the current month's billing kW. The opt-out penalties may be prorated to correspond with the dates of program operation and are accomplished through manual bill adjustments. The penalties will never exceed the amount of the incentive that would have been paid with full participation.

Program Activities

Idaho Power enrolled 2,335 service points in 2018, an increase of 1.7 percent over 2017. The enrolled service points accounted for 85.2 percent of the eligible service points. The total nominated kW increased to 416.8 MW from 411.2 MW in 2017.The company utilized two electrical contractors during the spring of 2018 to maintain and troubleshoot the AMI devices and cellular devices for dispatching. Identification and correction of device failures is an ongoing effort before the season begins and throughout the season.

Table 22. Irrigation Peak Rewards demand response event details

Event Details	Friday, July 13	Tuesday, July 17	Wednesday, August 1
Event time	2–9 p.m.	2–9 p.m.	2–9 p.m.
Average temperature	95°F	94°F	98°F
Maximum load reduction (MW)	296.7	256.6	263.8

The program administration expenses were less in 2018 because the company completed the upgrade of load control communication devices located on participating customers' pump electrical panels in 2017. Third-party load control devices were exchanged from cellular communication to Idaho Power's AMI communication. Third-party device management discontinued in December 2016. The lower 2018 expenses reflect the program in a maintenance mode with the devices being managed internally.

Marketing Activities

Idaho Power used workshops, trade shows, and direct-mailings to encourage past participants to re-enroll in the program. The company updated a program brochure to improve readability and answer common questions. The brochure, sign-up worksheet, and contract agreement were mailed to all eligible participants in March 2018. See the Irrigation Sector Overview section for additional marketing activities.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for the demand response programs under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2018.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 296.7 MW. The total expense for 2018 was $6.9 million and would have been approximately $9.8 million if the program was operated for the full 60 hours.

A complete description of cost-effectiveness results for Idaho Power's demand response programs is included in *Supplement 1: Cost-Effectiveness.*

Evaluations

Each year, Idaho Power produces an internal report of the Irrigation Peak Rewards program. This report includes a load-reduction analysis, cost-effectiveness information, and program changes. A breakdown of the load reduction for each event day and each event hour including line losses is shown in Table 23. A copy of the 2018 Irrigation Peak Rewards program report is included in *Supplement 2: Evaluation*.

Table 23. Irrigation Peak Rewards program MW load reduction for events

Event Date	2:00–3:00 p.m.	3:00–4:00 p.m.	4:00–5:00 p.m.	5:00–6:00 p.m.	6:00–7:00 p.m.	7:00–8:00 p.m.	8:00–9:00 p.m.
July 13	75.9	149.3	231.8	296.7	218.0	139.3	58.3
July 17	71.3	125.9	206.8	256.6	180.9	121.5	43.6
August 1	54.3	117.3	206.8	263.8	208.5	142.7	54.6

2019 Program and Marketing Strategies

Idaho Power will continue to recruit past participants in this program for the 2019 irrigation season; no program changes are expected. The company will include information on the program at its irrigation workshops in conjunction with the Irrigation Efficiency Program. Each eligible customer will be sent a comprehensive packet containing an informational brochure, sign-up worksheet, and contract agreement encouraging their participation. Idaho Power agricultural representatives will continue one-on-one customer contact to inform and encourage program participation.

Other Programs and Activities

Green Motors Initiative

Idaho Power participates in the Green Motors Practices Group's (GMPG) Green Motors Initiative (GMI). Under the GMI, service center personnel are trained and certified to repair and rewind motors in an effort to improve reliability and efficiency. If a rewind returns a motor to its original efficiency, the process is called a "Green Rewind." By rewinding a motor under this initiative, customers may save up to 40 percent when compared to buying a new motor. The GMI is available to Idaho Power's agricultural, commercial, and industrial customers.

Twenty-four service centers in Idaho have the training and equipment to participate in the GMI and perform an estimated 1,200 Green Rewinds annually. Of the 24 service centers, currently nine have signed on as GMPG members in Idaho Power's service area. The GMPG will work to expand the number of service centers participating in the GMI, leading to market transformation and an expected kWh savings in southern Idaho and eastern Oregon.

Under the initiative, Idaho Power pays service centers $2 per hp for each National Electrical Manufacturers Association (NEMA)-rated motor up to 5,000 hp that received a verified Green Rewind. Half of that incentive is passed on to customers as a credit on their rewind invoice. The GMPG requires all member service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG is responsible for verifying quality assurance.

In 2018, a total of 51 motors were rewound under the GMI. Table 24 provides a breakdown of energy savings and the number of motors by customer segment.

Table 24. Green Motor Initiative savings, by sector and state

Sector	State	Number of Motors	Sum of kWh Savings
Irrigation	ID	26	67,676
	OR	0	0
Irrigation Total		**26**	**67,676**
Commercial and Industrial	ID	25	64,167
	OR	0	0
Commercial and Industrial Total		**25**	**64,167**
Grand Total		**51**	**131,843**

Local Energy Efficiency Funds

The purpose of Local Energy Efficiency Funds (LEEF) is to provide modest funding for short-term projects that do not fit within Idaho Power's energy efficiency programs but provide a direct benefit to the promotion or adoption of beneficial energy efficiency behaviors or activities. Idaho Power received four LEEF applications in 2018: two from residential customers and two from commercial customers. None were funded.

The residential applications were reviewed and deemed not appropriate for LEEF because the products referenced in the submittal were found to be standard and widely available. For example, one applicant was seeking funds to replace an older door and windows. An Idaho Power residential program specialist and/or a customer representative followed up with the applicants to discuss other available incentives and to address other needs.

The two commercial customers requested assistance with LED lighting retrofits. In these cases, a program specialist directed applicants to program incentive information currently available from Idaho Power to support their projects.

Idaho Power's Internal Energy Efficiency Commitment

Idaho Power continues to upgrade the company's substation buildings across its service area. The existing grass and low-level evergreen shrub landscaping at the Fremont substation in Pocatello was removed and replaced with gravel. The irrigation system was greatly reduced to promote water conservation and reduced O&M expenses related to watering, mowing, and disposal of landscaping debris. This xeriscape approach will be considered for other substations. Efforts in 2018 also focused on providing energy-efficient heating and cooling. In 2018, Idaho Power replaced the make-up air handlers in the corporate headquarters (CHQ). The inefficient single-fan/single-speed units were replaced with state-of-the-art FANWALL® technology. Each unit consists of 12 VFD fans and will reduce energy consumption at the CHQ building while delivering a more consistent air flow for employees.

Renovation projects continued at the CHQ in downtown Boise, with a project to exchange the old T-12 parabolic lighting fixtures with LED lighting throughout 2019. Remodels continued to incorporate energy efficiency measures, such as lower partitions, other lighting retrofits, and automated lighting controls.

In Blackfoot, Pocatello, Twin Falls, and many other areas within Idaho Power's service area, the company continued to replace existing high bay lighting in truck bays and shops with more efficient LED lighting and to install smart thermostats throughout the enterprise.

In 2018, the design was completed for the new HVAC system at the Maintenance and Electrical Shops; construction on these projects is scheduled for 2019. These improvements to the shops will reduce energy consumption in coming years.

The Idaho Power CHQ building participated in the Flex Peak Program again in 2018 and committed to reduce up to 200 kW of electrical demand during events. Unlike other program participants, Idaho Power does not receive any financial incentives for its participation. Idaho Power's CHQ participated in all three demand response events in 2018. Idaho Power's other internal energy efficiency projects and initiatives are funded by non-rider funds.

Idaho Power continued a major sustainability initiative to educate employees about the purchase and use of electric vehicles (EV). A 2018 Chevy Bolt, with a range of 238 miles per charge, was purchased for use as a CHQ employee fleet car. Additionally, the company purchased and upfitted eight Ford F-150s with XLP™ Plug-in Hybrid systems designed to improve gas mileage and decrease emissions before placing them in service. These hybrid trucks are the first step in a transition to an all-electric truck fleet in the future. EV charging stations were installed to charge these vehicles.

Figure 41. Vehicles wrapped with graphics to promote Idaho Power's use of EVs

Market Transformation: NEEA

Market transformation is an effort to permanently change the existing market for energy efficiency goods and services by engaging and influencing large national companies to manufacture or supply more energy-efficient equipment. Through market transformation activities, participants promote the adoption of energy-efficient materials and practices before they are integrated into building codes. Idaho Power achieves market transformation savings primarily through its participation in the NEEA.

Idaho Power has funded NEEA since its inception in 1997. NEEA's role is to look to the future to find emerging opportunities for energy efficiency and to create a path forward to make those opportunities a reality in the region.

NEEA's current, five-year funding cycle began 2015. In this cycle, the NEEA business plan is forecast to obtain 145 average megawatts (aMW) of regional energy savings at a cost of about $13.5 million or approximately $2.7 million per year for Idaho Power customers. The NEEA plan also offered some optional programs and activities to prevent overlapping activities when local utilities have the capability to provide the same services at a lower cost or more effectively.

In 2018, NEEA and its funders began planning the next five-year cycle which will be from 2020–2024. The estimated cost for Idaho Power's customers in this funding cycle is $14.7 million, or $3 million per year.

Idaho Power participates in all of NEEA's committees and workgroups, including representation on the Regional Portfolio Advisory Committee and the Board of Directors. Idaho Power representatives participate in the Regional Portfolio Advisory Committee, Cost-Effectiveness and Evaluation Advisory Committee, Residential Advisory Committee, Commercial Advisory Committee, Regional Emerging Technologies Advisory Committee, Idaho Energy Code Collaborative, Ductless Heat Pump Workgroup, Heat Pump Water Heater Workgroup, and the Northwest Regional Strategic Market Plan for Consumer Products Group. The company also participates in NEEA's initiatives including the Residential Building Stock Assessment, Commercial Building Stock Assessment, Commercial Code Enhancement (CCE), Strategic Energy Management, Commercial Lighting - Reduced Wattage Lamp Replacement, Top-Tier Trade Ally and Luminaire Level Lighting Controls

NEEA performs several market progress evaluation reports (MPER) on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports, through third-party contractors, for energy efficiency initiatives throughout the Pacific Northwest. Copies of these and other reports mentioned below are referenced in *Supplement 2: Evaluation* and on NEEA's website under Resources & Reports. For information about all committee and workgroup activities, see the information below.

NEEA Marketing

As stated in Idaho Power's agreement with NEEA for the 2015 to 2019 funding cycle: "Idaho Power will fund, create, and deliver specific market transformation activities for all initiatives that are relevant for the Idaho Power service area." In 2018, these activities included educating residential customers on HPWH and ductless heat pumps, and educating commercial customers and participating contractors on reduced-wattage lightbulb replacement, NXT Level Lighting Training, and LLLC.

Idaho Power promoted ductless heat pumps and HPWH as part of its H&CE Program. The company also promoted DHPs as part of its residential marketing campaign. Full details can be found in the H&CE Program's Marketing section.

Idaho Power continued to encourage trade allies to take the NXT Level Lighting Training. The company also handed out flyers at seven trade ally lighting workshops in July and August.

To promote LLLC, Idaho Power held training classes in February in Boise and March in Pocatello. The company also rolled out a networked lighting control incentive in August.

NEEA Activities: All Sectors

Cost-Effectiveness and Evaluation Advisory Committee

The advisory group meets three to four times a year to review evaluation reports, cost-effectiveness, and savings assumptions. One of the primary functions of the work group is to review all savings assumptions that have been updated since the previous reporting cycle. The process usually requires a webinar and an all-day meeting. Other activities for 2018 included reviewing NEEA evaluation studies and data-collection strategies and previewing forthcoming research and evaluations.

Idaho Energy Code Collaborative

Since 2005, the State of Idaho has been adopting a state-specific version of the IECC. The Idaho Energy Code Collaborative is a group of individuals with varying backgrounds and levels of association with the building construction industry. The group's work is facilitated by NEEA. The purpose of the group is to make recommendations to the Idaho Building Code Board (IBCB) on the adoption of certain construction and energy codes in the residential and commercial sectors. Idaho Power is a member of this group and participates in the group's meetings.

The IBCB adopted the 2017 Idaho Energy Conservation Code (2015 IECC commercial provisions and 2012 IECC residential provisions with Idaho amendments) effective January 1, 2018.

In September 2018, commercial and residential construction and energy codes were published by the International Code Council (ICC). The publications include the *2018 International Building Code, 2018 International Existing Building Code*, *2018 International Residential Code, 2018 International Energy Conservation Code* (residential), and the *2018 International Energy Conservation Code* (commercial). The Idaho Energy Code Collaborative reviewed these publications in detail, comparing them to the prior codes published in 2015. The results of the comparison were provided to the IBCB as the they began formally reviewing these publications in November for potential adoption.

Idaho Power participated and offered support in those collaborative meetings, which were attended by members of the building industry, local building officials, code development officials, and other interested stakeholders. Idaho Power also attended the IBCB public meetings. The Idaho Energy Code Collaborative is an effort in which Idaho Power will continue to participate.

Regional Emerging Technologies Advisory Committee

Idaho Power participated in Regional Emerging Technologies Advisory Committee (RETAC) which met quarterly to review the emerging technology pipeline for BPA, NEEA, and the Northwest Power and Conservation Council (NWPCC) Seventh Power Plan. Throughout 2018, RETAC focused on technologies for residential HVAC, commercial HVAC, and water heating. RETAC discussed the gaps and issues that exist for these technologies and how NEEA and the regional utilities can address those issues. This discussion will continue in 2019.

Regional Portfolio Advisory Committee

The Regional Portfolio Advisory Committee (RPAC) is responsible for overseeing NEEA's market transformation programs and their advancement through key milestones in the "Initiative Lifecycle." RPAC members must reach a full-consent vote at selected milestones in order for a program to advance to the next stage; members can exercise a "challenge flag" at any stage if a program goes beyond the scope agreed upon by the committee.

RPAC convenes in-person for quarterly meetings and by webinar as needed. In 2018, the RPAC conducted three quarterly meetings and five marketing-related meetings with a group that was labeled RPAC+, which included regular RPAC members and marketing representatives from each organization.

In the first regular quarterly meeting of RPAC on February 28, the group voted to support advancing Industrial Motor Product Labeling/Extended Motor Products (XMP) through the Initiative Star Milestone and into NEEA's program portfolio. NEEA staff conducted a NEEA portfolio review and an emerging technologies update.

On May 14, RPAC met at the Seattle-Tacoma Airport. The RPAC was shown the 2018 RPAC Workplan and voted to move Very High Efficiency Dedicated Outside Air Systems (VHE DOAS) through the Initiative Start milestone and into NEEA's program portfolio. NEEA staff updated the group and a discussion was held concerning NEEA's 2020 to 2024 Business Planning Workshop, which addressed a complementary approach for initiatives and the right-sizing advisory committees. RPAC also reviewed the Commercial/Industrial lighting regional strategic market plan.

On August 22, RPAC began an in-depth investigation into how NEEA promotes market transformation with the goal of providing guidance to the board. The group also discussed streamlining the Initiative Life Cycle Process and decreasing the number of committees and workgroups. NEEA staff presented updates on emerging technologies and market research and evaluation.

After one funder threw the challenge flag and a subsequent board directive, RPAC+ held marketing workshops on September 26 and October 3, 11, 18, and 23 to resolve issues relating to NEEA's downstream marketing activities.

Idaho Power staff participated in RPAC+ workshops that were organized to propose guiding principles on how NEEA will conduct downstream marketing activities in Cycle 6, which runs from 2020 through 2024. Downstream marketing activities were defined as region-wide marketing activities to promote energy-efficient products, services, and practices directly to end-users including digital ads, purchased social, billboards and print, broadcast (radio/tv), point of purchase, and direct-mail where NEEA would historically use a market-facing sub-brand of a NEEA initiative.

These activities require additional coordination between NEEA and Idaho Power to limit customer confusion. Idaho Power staff spent significant time attending these weekly webinars and reviewing proposals to advocate for a process and outcome that would best serve Idaho Power customers. Ultimately, RPAC+ members agreed on the proposed downstream marketing methods except how a utility would be reimbursed if it opted out of a marketing campaign. This issue was sent back to the Board of Directors.

Throughout 2018, RPAC received updates on NEEA board discussions concerning the Strategic/ Business/Planning process for the 2020 to 2024 funding cycle and incorporating funders from natural gas utilities into NEEA.

NEEA Activities: Residential

Ductless Heat Pump Workgroup

Idaho Power continued participating in NEEA's Ductless Heat Pump Workgroup. Its members are primarily employees of electric utilities in the Northwest. The workgroup was formed several years ago to help support NEEA's regional market transformation activities around ductless heat pumps. In 2018, NEEA began creating a vetting process that will provide Northwest stakeholders an opportunity to communicate their opinions as to the readiness of the DHP initiative to transition to the last phase of the Initiative Lifecycle, called Long Term Monitoring and Tracking (LTMT).

The vetting process will extend into Q3 2019, and the Ductless Heat Pump Workgroup will provide assistance to the NEEA program manager during this time. To help inform stakeholders, the 8th MPER was initiated in December 2018 and will be published in Q3 2019. Other available information includes the 2019 DHP Operations Plan released in September and the DHP Initiative Lifecycle released in July. A stakeholder workshop is also planned for early 2019.

Heat Pump Water Heater Workgroup

Idaho Power continued participating in NEEA's Heat Pump Water Heater Workgroup. Its members are primarily employees of electric utilities in the Northwest. The workgroup was formed several years ago to help support NEEA's regional market transformation activities around HPWHs. The work in 2018 remained focused on activities to accelerate market transformation. The workgroup continued to assist the Northwest Regional Strategic Market Plan for Consumer Products group, which was also focused on HPWHs.

Northwest Regional Strategic Market Plan for Consumer Products Group

Idaho Power has been a member of the Northwest Regional Strategic Market Plan for Consumer Products group since its inception in 2016. Idaho Power continued its membership in 2018 and participated as member of its steering committee. The members are primarily employees of electric utilities in the Northwest. The group was formed based on NEEA's determination that a strong focus needed to be placed on the performance of certain consumer products to obtain their maximum contributions to Northwest energy efficiency.

In late 2017, the focus expanded from HPWH to include smart thermostats. In 2018, the steering committee assembled a Smart Thermostat Savings Task Force, asking them to create a research proposal. The RTF requested research to help the them decide if smart thermostats can be advanced to a deemed measure from their current planning measure status. The contract analyst presented the research proposal in September, which the RTF approved. The research would be performed in 2019 and 2020. In late 2018, the steering committee discussed the needed funding and how a regional request could be accomplished.

Residential Advisory Committee

Idaho Power participates in the Residential Advisory Committee (RAC), the Manufactured Homes Interest Group, the Retail Products Portfolio (RPP) Initiative, Efficient Homes Workgroup, the Super-Efficient Dryers Workgroup, and Northwest Regional Retail Collaborative. During 2016, NEEA combined the Efficient Homes Workgroup and the Manufactured Homes Interest Group and renamed it the BetterBuiltNW Workgroup.

Idaho Power participated in RAC, which met quarterly in 2018, with the exception of the Q4 meeting which was cancelled by NEEA due to lack of agenda items. The purpose of the RAC is to advise NEEA with broad-based advice, experience, and feedback in all residential program matters. This committee provides utilities with the opportunity to give meaningful input into the design and implementation of NEEA programs.

NEEA provides BetterBuiltNW builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates energy-efficient new construction activities with utilities in Idaho, Montana, Oregon, and Washington. In 2018, NEEA continued to assist utilities in launching custom single-family Residential Performance Path programs that offer utilities flexibility in program design and the opportunity to capture all above-code savings on residential new construction projects. NEEA will continue to manage the AXIS regional database. NEEA continued to work on an above-code manufactured homes specification, known as NEEM 2.0. This specification will eventually replace the current NEEM 1.1 specification.

The Super-Efficient Dryers Initiative was formed to support the acceleration of heat pump dryers into the market. The initiative focuses on influencing manufacturer product development and executing strategies to overcome the barriers of this new technology. Barriers include a high incremental cost, limited consumer awareness, and low product availability. The initiative offers incentives to reduce the retail price. In 2018, NEEA staff conducted lab tests and worked with the RTF to update the clothes dryer measure. As a result of the testing, the UES values for ENERGY STAR® clothes washers were increased.

A Multifamily Market Research Online Community group was created to help gain an understanding of the drivers, market players, and influences in multifamily building management, with the hopes of persuading multifamily developers, property managers, etc., to begin using heat pump dryers in their units.

Continued retailer pilots with Blomberg were offered, providing rebates for the purchase of qualified heat pump dryers and heat pump hybrid dryer units. One of the 2019 goals is to add promotions and rebates for clothes washers because washer performance affects the performance of heat pump dryers. The use of a high-efficiency washer leaves less moisture in the clothing, which allows the heat pump and heat pump hybrid dryer to work more efficiently. It would be ideal to market these units as a pair to ensure high satisfaction with the heat pump dryers.

The RPP Initiative was formed to provide mid-stream incentives to influence retail stocking and assortment practices that would eventually drive manufacturing and standards toward a portfolio of energy-efficient products sold through retail channels. In 2018, there were seven qualifying products and two tiers assigned to each product: basic and advanced. The incentive is not intended to buy down the purchase, but rather to influence stocking practices.

Residential Building Stock Assessment

NEEA released the results of the Residential Building Stock Assessment (RBSA) in early 2018. Results from the study were incorporated in Idaho Power's potential study to fill data gaps, as needed. The RTF will continue to update the deemed savings values and input parameters for residential energy-savings measures based on the results of the RBSA.

NEEA Activities: Commercial/Industrial

NEEA continued to provide support for commercial and industrial energy efficiency activities in Idaho in 2018, which included partial funding of the IDL for trainings and additional tasks.

Commercial Building Stock Assessment

NEEA began work on the Commercial Building Stock Assessment (CBSA) in 2018. The CBSA is conducted approximately every five years, and the information is used by utilities in the Pacific Northwest and the NWPCC to determine load forecast and electrical energy-savings potential in the region.

For commercial customers who choose to participate in the study, the third-party contractor schedules a site visit with a field technician who collects information on equipment and building characteristics that affect energy consumption. This includes HVAC equipment, lighting, building envelope, water heating, refrigeration and cooking, computers and miscellaneous equipment, and cooling towers. Participants receive a gift card and a site-specific report.

To prepare for the study, Idaho Power staff participated in the sampling and customer contact working groups. The sampling working group met to review and approve the sampling plan while the customer contact working group discussed the recruitment process and the customer contact protocols. A pre-test was conducted in Portland and Boise in fall of 2018 to test the recruitment process. The full study launched in late 2018; Idaho Power commercial customers will be contacted throughout 2019.

Commercial Code Enhancement

NEEA facilitated regional webinars for the CCE initiative for new construction to discuss how utilities can effectively align code changes and utility programs. The CCE is a NEEA initiative comprised of people with varying backgrounds and levels of association with the building construction industry. The group's goal is to enable the continual advancement of commercial construction and energy codes.

A subset of this group's work in 2018 included a Scanning Report that identified measures to be considered in future codes. This work will continue in 2019.

Strategic Energy Management

NEEA's work on SEM in the commercial and industrial sectors continued in 2018. The primary focus in 2018 was to consolidate all of the SEM templates, guidelines, and documents into the new SEM Hub website.

Commercial Lighting

Idaho Power participated in NEEA's initiatives in the commercial lighting arena. Idaho Power continued as a member of the NEEA Commercial Lighting Program Manager Work Group and the Commercial Advisory Committee.

Reduced Wattage Lamp Replacement

The Reduced Wattage Lamp Replacement (RWLR) initiative concluded December 2018. NEEA has converted this initiative to a long-term monitoring and tracking activity.

Top-Tier Trade Ally

The Top-Tier Trade Ally initiative offers lighting trade allies throughout the region multi-tiered training. One hundred seventy-nine individuals from 47 regional companies successfully completed NXT Level 1 Training and attained Top-Tier Trade Ally designation by the end of 2018. Eight individuals in Idaho Power's service area achieved the designation, for a total of 18 individuals program-to-date. To date, one company is designated as a Top-Tier Trade Ally in the Idaho Power service area.

NEEA launched a one-hour Jump Start training session in 2018 to aid in recruiting new NXT Level 1 students. The Jump Start session fulfilled one of the NXT Level training modules, which increased the interest for attendees to get involved in this valuable training. The Jump Start training was offered at four of Idaho Power's program update workshops in 2018. As a result, 36 people submitted enrollment applications for NXT Level 1 training. Five of those applicants completed the training and received designation.

NXT Level 2 training curriculum was finalized in 2018 and launched in fourth quarter. Currently, NXT Level 2 is an in-person curriculum. NEEA is rolling out this training to areas with higher NXT Level 1 designated populations. Development is underway to offer an online version of NXT Level 2 training. This version is expected to be available to the Idaho Power service area mid-2019.

Luminaire Level Lighting Controls

Idaho Power hosted two Advanced Lighting Controls classes in 2018. The classes were a follow-up to the pilot course the company hosted in 2017. The 2018 classes were held in Boise and Pocatello and both were well received. The DLC coordinated the training and curriculum, and NEEA helped sponsor the classes.

NEEA also partnered with the Seattle LDL to develop a one-day Advanced Lighting Controls curriculum targeted to electrical contractors and electrical equipment suppliers. The new course is an enhancement to the DLC class and was made available for utilities in their service area in 2019. Idaho Power plans to host a session in 2019.

By the end of 2018, 18 LLLC systems were available in the market. NEEA continues to work with manufacturers to help them achieve LLLC designation. NEEA, in partnership with the DOE's Next Generation Lighting System initiative, continues to work with manufacturers to improve product usability and ease of product installation.

NEEA Funding

In 2018, Idaho Power began the fourth year of the 2015 to 2019 *Regional Energy Efficiency Initiative Agreement* with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2018, 100 percent was funded through the Idaho and Oregon Riders.

In 2018, Idaho Power paid $2,500,165 to NEEA; $2,375,157 from the Idaho Rider for the Idaho jurisdiction and $125,008 from the Oregon Rider for the Oregon jurisdiction. Other expenses associated with Idaho Power's participation in NEEA activities, such as administration and travel, were also paid from Idaho and Oregon Riders.

Final NEEA savings for 2018 will be released in June 2019. Preliminary estimates reported by NEEA for 2018 indicate Idaho Power's share of regional market transformation savings as 24,966 MWh. These savings are reported in two categories: codes-related and standards-related savings of 21,724 MWh and non-codes and standards-related savings of 3,241 MWh.

In the *Demand-Side Management 2017 Annual Report*, preliminary funding share estimated savings reported were 23,652 MWh. The revised estimate included in this report for 2017 final funding-share NEEA savings is 24,440 MWh. These include savings from code-related initiatives as well as non-code-related initiatives. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website, neea.org.

Program Planning Group

In 2014, Idaho Power convened an internal PPG to explore new opportunities to expand current DSM programs and offerings. The group consists of residential program specialists, commercial and industrial engineers, energy efficiency analysts, marketing specialists, energy efficiency program leaders, and the research and analysis leader. The PPG does not perform program execution. Instead, the group's role is to determine if a measure has energy-saving potential, has market adoption potential, and is potentially cost-effective. If a measure meets those preliminary criteria, it is given to the program teams to implement.

Throughout 2018, the group met periodically to explore new ideas to promote energy efficiency, including evaluating new potential programs and measures. Idaho Power incorporated three new ideas from the PPG into the overall portfolio of residential and commercial program offerings: HPWHs, Commercial Energy-Saving Kits, and the Residential New Construction Pilot Program. These offerings will continue to be available in 2019.

In addition to the offerings that were implemented, the company continued to pursue and investigate other new ideas, such as residential weatherization measures for direct-install and a small business direct-install program for measures such as lighting or plug strips. Based on the criteria cited above, these offerings could be launched in 2019. Idaho Power will continue to use the PPG to review, evaluate, and deliver new energy efficiency offerings in 2019 and beyond.

Regional Technical Forum

The RTF is a technical advisory committee to the NWPCC, established in 1999 to develop standards to verify and evaluate energy efficiency savings. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, participating in sub-committees, and sharing research and data beneficial to the forum's efforts.

The forum is made up of both voting members and corresponding members from investor-owned and public utilities, consultant firms, advocacy groups, Energy Trust of Oregon, and BPA, all with varied expertise in engineering, evaluation, statistics, and program administration. The RTF advises the NWPCC during the development and implementation of the regional power plan in regard to the following listed in the RTF charter:

- Developing and maintaining a readily accessible list of eligible conservation resources, including the estimated lifetime costs and savings associated with those resources and the estimated regional power system value associated with those savings.
- Establishing a process for updating the list of eligible conservation resources as technology and standard practices change, and an appeals process through which utilities, trade allies, and customers can demonstrate that different savings and value estimates should apply.
- Developing a set of protocols by which the savings and system value of conservation resources should be estimated, with a process for applying the protocols to existing or new measures.
- Assisting the Council in assessing: 1) the current performance, cost, and availability of new conservation technologies and measures; 2) technology development trends; and 3) the effect of these trends on the future performance, cost, and availability of new conservation resources.
- Tracking regional progress toward the achievement of the region's conservation targets by collecting and reporting on regional research findings and energy savings annually.

When appropriate, Idaho Power uses the savings estimates, measure protocols, and supporting work documents provided by the RTF, and when the work products are applicable to the climate zones and load characteristics in Idaho Power's service area. In 2018, Idaho Power staff participated in all RTF meetings as a voting member and the RTF Policy Advisory Committee. Idaho Power staff is represented at the RTF for the three-year forum member term cycle beginning in 2019.

Measure changes enacted for existing and possible new measures are reviewed throughout the year for potential impacts to programs and measures. All implementations of changes were accounted for in planning and budgeting for 2019.

Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The REEEI promotes energy efficiency to the residential sector. The company achieves this by creating and delivering educational materials and programs that result in wise and informed choices regarding energy use and increased participation in Idaho Power's energy efficiency programs.

Project Tiny House

In 2018, Idaho Power collaborated with Metro Community Services (Metro) and Canyon-Owyhee School Service Agency (COSSA) to build a tiny house. Idaho Power provided $3,500 for the purchase and installation of a DHP. Metro is an Idaho nonprofit that helps seniors, low-income people, and those with disabilities. COSSA is a trade and craft high school with students from Marsing, Homedale, Notus, Parma, and Wilder.

Metro supplied or secured the remaining supplies, and the COSSA students learned various aspects of construction through hands-on building of the tiny house. The completed tiny house was displayed at trade shows and other promotional events within Idaho Power's service area. Approximately 10 students in grades 10 through 12 worked on the home from November 2017 through June 2018, which was raffled off in September of 2018 to raise funds for senior services.

Figure 42. Tiny house

Idaho Power's promotion of Project Tiny House included custom signage to hang inside the home highlighting the energy-efficient features. Additional promotion included an article in the April issue of *Connections*. The tiny house drew customers at several events, such as March for Meals, Incredible Age Expo, Annual Information Fair, Experience Idaho Expo, Wells Fargo Sustainability Fair, HP World Environment Day, Meridian Public Works Expo, World Village Fest, Culinary Walkabout, Canyon Country Fair, and various Home Depot's throughout the Treasure Valley.

In 2018, Idaho Power partnered with Project Tiny House for the 7th annual Treefort Music Fest, held across the street from Idaho Power CHQ in downtown Boise. The annual festival brings nearly 20,000 local residents and others from around the region to the downtown area over five days of music and community-oriented programming. The partnership was a resounding success. Not only did the attraction of the Tiny House help increase the number of attendees who interacted with Idaho Power staff to learn about the company's parks and campgrounds, but the Project Tiny House team was able to sell 25 tickets for their 2018 raffle for the home.

The tiny house proved to be of great interest to curious customers at a variety of events. This gave an opportunity for customers to see what a DHP looked like installed in a wall and to feel the air conditioning it could provide. The home also provided opportunities to talk about various other energy efficiency measures, such as LED lighting and low-flow showerheads, as well as measures that are not readily visible, such as spray foam insulation.

While the tiny house proved useful for attracting and engaging customers, it was not a successful fundraiser for Metro, so they decided to discontinue the project.

Kill A Watt Meter Program

The Kill A Watt™ Meter Program remained active in 2018. Idaho Power's Customer Service Center and field staff continued to encourage customers to learn about the energy used by specific appliances and activities within their homes by visiting a local library to check out a Kill A Watt meter.

Figure 43. Kill A Watt meter

The Kill A Watt meter brochure was updated in 2018. The Kill A Watt meters were mentioned again on live television studio news programs on KTVB and KMVT in Idaho Power's monthly energy efficiency segments and highlighted in the 2018 Winter *Energy Efficiency Guide*. Late in 2017, Idaho Power contacted participating libraries to determine what, if any, replacements were needed. Those communications continued into 2018. Forty-three libraries responded with requests for additional materials, including new meters, replacement kits, brochures and/or 30 Simple Things You Can Do to Save Energy booklets.

Teacher Education

As in previous years, Idaho Power continued to strengthen the energy education relationship with secondary school educators through continued participation on the Idaho Science, Technology, Engineering, and Mathematics (iSTEM) Steering Committee. In 2018, Idaho's STEM Action Center assumed the responsibility for overseeing the state's iSTEM Institutes. This strategic change of leadership resulted in many positive outcomes; however, some challenges in the enrollment process resulted in lower enrollments. In 2018, 13 teachers completed the four-day, two-credit professional development workshop offered at the College of Western Idaho's iSTEM Institute. The workshop "Electrons—Pushing, Using, and Saving Them!" was facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Laboratory (INL). Among other things, participating teachers toured the Langley Gulch power plant and received a classroom kit containing Kill A Watt meters and other tools to facilitate student learning related to energy efficiency and wise energy use. Idaho Power took advantage of the extra space in the 2018 workshop to introduce its five community education representatives to STEM practices and concepts. These employees regularly interact with students and teachers in the schools and are increasingly used to bring relevant STEM activities into schools and classrooms in Idaho Power's service area. By participating in the 2018 workshop, teachers developed skills and relationships to help them engage middle school and high school students in activities and conversations around future energy needs, and energy efficiency options and choices.

Student Art Contest

Idaho Power held its 8th Annual Student Art Contest for grades K-9. Kindergarten through second grade completed a simple color page highlighting safety. Students in grades 3-9 were tasked with creating original artwork based on the themes "Ways to Save Energy" or "Environmental Stewardship." Many students drew pictures of their favorite ways to save energy in the home. The Student Art Contest provides a way for teachers and students to bring energy efficiency education into their classroom and inspire students and families to think more about energy. With 4,654 submissions, over 30 students were recognized with first- and second-place awards. Over the years, student artwork has been displayed in local schools, libraries and city halls, and at events such as the annual Idaho Environmental Education Conference and elementary school STEM nights. Students in both Idaho and Oregon participated in 2019 (3,827 Idaho and 827 Oregon).

Figure 44. Eighth annual Student Art Contest participants

Program Support

In 2018, 44,691 ESKs were shipped with a mini-home assessment to cross-market other energy efficiency programs, promote the use of My Account, and help families learn about other energy-saving behavior changes. Savings and expenses have been reported in the Educational Distributions residential program section of this report.

The initiative continued to coordinate LED lightbulb distributions aimed at providing the newest lighting technology to customers, along with education and answers to their common questions. At events and presentations, company staff distributed 9,450 LEDs in custom packaging that highlighted the advantages of energy-efficient lighting and encouraged participation in Idaho Power's My Account online portal. Customer representatives throughout the service area also handed out 700 Giveaway ESKs containing nine LED lightbulbs and other educational materials in conjunction with energy efficiency presentations and workshops. The energy savings resulting from these efforts and from the SEEK program for the 2017–2018 school year are also reported in the Educational Distributions residential program section of this report.

The initiative also implemented a Welcome Kit program with the goal of proactively introducing each first-time customer to sound, energy-saving practices along Idaho Power's energy efficiency programs at a moment when they may be receptive to hearing and implementing change. In the first year, approximately 30,500 brand new customers received a Welcome Kit delivered to their home about 30-45 days after they moved in. Each kit contained four LED lightbulbs, a night light, a "Welcome to the Neighborhood" greeting card, and a small, easy-to-use, tabbed flip-book filled with helpful energy-saving tips and energy efficiency program information.

The initiative continued to manage the HER pilot program. During the year, 105,626 reports were sent to over 29,000 participants across the service area. The customized reports, delivered to customers at regular intervals, showed customers how their energy use compared to other homes in their respective communities with similar characteristics (i.e., home size, type, and heating source). In addition to the comparisons, the *Home Energy Reports* provided participants with a personalized breakdown of how electricity is used in their home (disaggregated energy use), along with customized energy-saving tips and suggestions. Idaho Power determined to continue the pilot for a second year—adding 5,624 new winter-heating participants. The new group will receive bi-monthly reports. The results of both pilot years will be analyzed in late summer 2019. At that time, Idaho Power will decide whether to continue or expand the HER pilot.

Marketing

REEEI continued to produce semiannual *Energy Efficiency Guide*s in 2018. Idaho Power distributed these guides primarily via insertion in local newspapers and at events across Idaho Power's service area. The winter *Energy Efficiency Guide* was published and distributed by 17 newspapers in Idaho Power's service area the week of January 28; the *Boise Weekly* also inserted the guide. The guide focused on providing answers to a number of interesting energy efficiency questions customers had recently asked. Along with useful energy-saving tips, the guide addressed hot tubs, programmable pressure cookers, high efficiency washers, portable space heaters, and ENERGY STAR® smart thermostats. The information was applicable to all residential customers and designed to be family friendly. Idaho Power included a story from the guide in January *News Briefs*, *News Scans*, and a promo pod on the idahopower.com homepage.

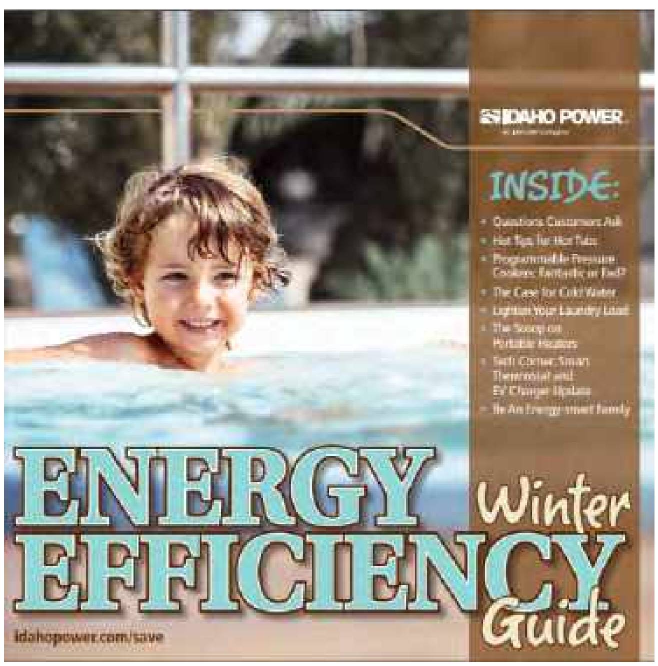


Figure 45. Winter *Energy Efficiency Guide*, 2018

The *Idaho Statesman* hosted Idaho Power's print ads, digital ads, and banner ads promoting the guide, including a one-day online homepage takeover on January 27, resulting in 173,223 impressions, 342 click throughs, and a click through rate of 20 percent. The newspaper also hosted a 30-second energy efficiency commercial as a video pre-roll from January 28 to February 28. An Idaho Power Facebook boost was used to promote the guide to Idaho Power followers.

The summer *Energy Efficiency Guide* was delivered to over 194,000 homes the week of July 29, 2018. This guide highlighted efficient ways to stay comfortable during the hot summer months and specific room-by-room tips for reducing energy use at home and while on vacation. It also discussed how to use landscaping to increase a home's comfort and boost energy efficiency.

The release of the summer guide received public relations support through numerous communication channels, including *News Briefs*, *News Scans*, on Idaho Power's social media accounts, and in digital ads on local newspaper websites, targeted to customers in the service area during the last week of July, including the *Times News*, *Idaho State Journal*, *Boise Weekly*, and *Idaho Press*. The summer guide was also mentioned during an Idaho Power interview on KBOI on July 13.

Both of the 2018 guides were translated into Spanish to help reach the larger Idaho Power customer base. In 2018, the company distributed a total of 5,500 guides, including issues from past years, at energy efficiency presentations and events. The current library of guides continues to add value. Specific issues are often requested for distribution at events and presentations based on their relevance to the particular audience. On its website, Idaho Power provides a link to the most current seasonal guide and links to past guides.

REEEI distributed energy efficiency messages through a variety of other communication methods in 2018. Idaho Power increased customer awareness of energy-saving ideas via continued distribution of the third printing of the 96-page booklet *30 Simple Things You Can Do to Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. The fourth printing of the booklet was updated to include a more colorful cover that aligns with the overall energy efficiency imagery. In 2018, the program distributed 2,560 copies directly to customers. This was accomplished via community events and local libraries; by customer representatives during in-home visits; by participating contractors in the Home Energy Audits program, Energy House Calls program, and H&CE Program through direct web requests; and in response to inquiries received by Idaho Power's Customer Service Center. Additionally, more than 44,000 customers had an opportunity to request the booklet and/or the most recent *Energy Efficiency Guide* when they ordered their ESK online.

Idaho Power continues to recognize that educated employees are effective advocates for energy efficiency and Idaho Power's energy efficiency programs. Idaho Power customer relations and energy efficiency staff reached out to each of Idaho Power's geographical regions and the Customer Service Center to speak with customer representatives and other employees to discuss educational initiatives and answer questions about the company's energy efficiency programs.

Idaho Power continued to participate in a select group of events impacting large audiences or audiences expected to have a higher receptivity to energy-efficient messaging and behavior change. Idaho Power once again participated in The Incredible Age Expo (targeting customers preparing for retirement), Boise's Treefort Music Fest (skewing to sustainably minded younger people), St. Luke's FitOne Expo, and numerous home and garden shows throughout the service area. Idaho Power participated in or sponsored an additional 45 outreach activities, including events, presentations, trainings, and other activities. Idaho Power customer representatives throughout the service area delivered numerous other presentations to local organizations addressing energy efficiency programs and wise energy use. In 2018, Idaho Power's community education team provided 118 presentations on *The Power to Make a Difference* to 3,063 students and 122 classroom presentations on *Saving a World Full of Energy* to 2,803 students. The community education representatives and other staff also completed 24 senior citizen presentations on energy efficiency programs and shared information about saving energy to 1,149 senior citizens in the company's service area. Additionally, Idaho Power's energy efficiency program specialists responded with detailed answers to 241 customer questions about energy efficiency and related topics received via Idaho Power's website.

Idaho Power used multiple channels to promote National Energy Awareness Month in October, including social media posts encouraging energy-efficient behaviors, as well as customer engagement in the Smart-Saver Pledge. The October *Connections*, two *News Briefs*, and the KTVB and KMVT monthly television spots also highlighted Energy Awareness Month activities.

The REEEI continued to provide energy efficiency tips in response to media inquiries and in support of Idaho Power's *#TipTuesday* posts. In addition to supplying information for various Idaho Power publications, such as *News Scans*, *Connections*, and Idaho Power's social media pages, energy efficiency tips and content were provided for weekly *News Briefs* and monthly KTVB and KMVT live news segments.

Several new videos, including customer testimonials and experiences, were made available on Idaho Power's YouTube channel. These included the following:

- Summer Learning with Idaho Power: youtube.com/watch?v=C90d72ZoPeI
- Energy Efficiency Quick Tip series (13 short clips): youtube.com/watch?v=X3JQdtNLtt4

2019 Program and Marketing Strategies

The initiative's 2019 goals are to increase customer awareness of the wise use of energy and program participation and to promote education and energy-saving ideas that result in energy-efficient, conservation-oriented behaviors. In addition to producing and distributing educational materials, the initiative will continue to manage the company's Educational Distributions program that distributes energy-savings educational measures. Examples of activities conducted under Educational Distributions include developing LED lighting education material, distributing LED lightbulbs and Giveaway ESKs to customers, and administering the SEEK program, the ESK program, Welcome Kit distribution, and the HER pilot program.

The initiative will continue to educate customers using a multi-channel approach and to work with the PPG to explore new technologies and/or program opportunities that incorporate a behavioral component.

University of Idaho Integrated Design Lab

Idaho Power is a founding supporter of the IDL. The IDL is dedicated to the development of high-performance, energy-efficient buildings in the Intermountain West. Idaho Power has worked with the IDL since its inception in 2004 to educate the public about how energy-efficient business practices benefit the business and the customer. In 2018, Idaho Power entered into an agreement with the IDL to perform the tasks and services described below.

Foundational Services

The goal of this task was to provide energy efficiency technical assistance and project-based training to building industry professionals and customers. When the IDL receives requests for their involvement in building projects, the projects are categorized into one of three types: Phase I projects are simple requests that can be addressed with minimal IDL time; Phase II projects are more complex requests that require more involvement and resources from the lab; Phase III projects are significantly more complex and must be co-funded by the customer.

In addition to 16 ongoing projects from 2017, the IDL provided technical assistance on 30 new projects in the Idaho Power service area in 2018: 16 Phase I projects, six Phase II and one proposed Phase III project. An additional seven projects are proposed for potential future work. Twelve of the projects were on new buildings, 11 on existing buildings, and the remaining were not building-specific. The number of projects increased in 2018 compared to 2017, and the total building area impacted was approximately 250,000 ft^2. The related report is located in the IDL section of *Supplement 2: Evaluation*.

Lunch & Learn

The goal of the Lunch & Learn task was to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions.

In 2018, the IDL scheduled 20 technical training lunches in Boise. The sessions were coordinated directly with architecture and engineering firms and organizations; a total of 194 architects, engineers, designers, project managers, and others attended.

The topics of the lunches (and number of each) were: Indoor Air Quality (IAQ) and Energy Efficiency in Buildings (6); Daylight Performance Metrics for Human Health, Productivity, and Satisfaction (4); Daylight in Buildings: Getting the Details Right (3); Chilled Beams (2); Radiant Heating and Cooling Design (3); Hybrid Ground Source Heat Pump Systems (1); and Variable Refrigerant Flows (VRF) & Heat Pumps (1). The related report is located in the IDL section of *Supplement 2: Evaluation*.

Building Simulation Users Group

The goal of this task was to facilitate the Idaho BSUG, which is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

In 2018, six monthly BSUG sessions were hosted by IDL. The sessions were attended by 72 professionals in-person and 85 professionals remotely. Evaluation forms were completed by attendees for each session. On a scale of 1 to 5, with 5 being “excellent” and 1 being “poor,” analyzing results from the first six questions, the average session rating was 4.11 for 2018. For the final question, “The content of the presentation was…” on a scale of 1 to 5, with 1 being “too basic,” 3 being “just right,” and 5 being “too advanced,” the average session rating was 3.42 for 2018.

Each presentation was archived on the BSUG 2.0 website along with general BSUG-related content. The related report is located in the IDL section of *Supplement 2: Evaluation*.

New Construction Verification

The goal of this task was to continue random installation verification of over 10 percent of the C&I Energy Efficiency Program New Construction participants who received incentives. The company conducted a review of documentation and completed on-site inspections to validate whether systems and components had been installed. The purpose of this verification was to confirm program guidelines and requirements were helping participants provide accurate information regarding measure installations. See the New Construction option in the C&I Energy Efficiency Program section for a summary of these activities. The complete verification report is located in the IDL section of *Supplement 2: Evaluation*.

This task also included the review of all daylight photo-control incentives to verify site conditions and improve the quality of design and installation.

Tool Loan Library

The TLL gives customers access to tools for measuring and monitoring energy consumption on various systems within their operations. The goal of this task was to operate and maintain the tool library, which includes a web-based loan-tracking system, and to provide technical training on the use of tools in the library.

The inventory of the TLL consists of over 900 individual pieces of equipment. In 2018, 20 new tools were added to replace old data logging models, as well as a new portable thermal camera with an external power supply for extended periods of use. The tools and manuals are available at no cost to customers, engineers, architects, and contractors in Idaho Power's service area to aid in the evaluation of energy efficiency projects and equipment they are considering.

There were 38 tool loan requests in 2018, by 22 unique users, including 11 new users from 14 different locations, including engineering firms, equipment representatives, educational institutions, industrial plants, and commercial facilities. The related report is located in the IDL section of *Supplement 2: Evaluation*.

Heat Pump Calculator/Climate Design Tools/TEST

This task was a continuation of work done in a task that began in 2013 and continued through 2018. The goal of the original task was to develop an Excel-based heat pump analysis tool to calculate energy use and savings based on site-specific variables for commercial buildings. Previously, IDL identified a lack of sophisticated heat pump energy-use calculators available with the capability of comparing the energy use of heat pumps in commercial buildings against other technologies in a quick, simple fashion.

The calculator has been updated to reflect feedback from validation testing, including an improved user interface and the ability to integrate Typical Meteorological Year, version three weather files for locations where that data is available. A few years ago, the IDL completed a set of Climate Design Tools intended to inform sustainable design and calculate the impacts of five innovative types of systems: earth tubes, passive heating, cross ventilation, stack ventilation, and night flush ventilation/thermal mass. In 2015, the IDL integrated three of the five climate design tools into the Heat Pump Calculator. This unification produced a single platform life-cycle analysis tool for several energy efficiency measures not currently well-supported with other tools in the industry. In 2016, the IDL unified two additional climate-design tools to the calculator and added seven unique weather files for sites around Idaho. The work in 2017 focused on outreach, education, and customization of the tool. In 2018, the tool was renamed to the Thermal Energy Savings Tool or TEST.

Outreach continued in 2018 but was not the main emphasis of the task. Even so, there were several new inquiries and tool downloads. The IDL included information on the TEST in many of the Lunch and Learn presentations delivered at architecture and engineering firms in Idaho. Whenever a user requested access to the tool, the IDL sent the TEST spreadsheet through the service WeTransfer because it is too large to attach in a traditional email. A disclaimer is included with each tool download that makes clear the tool does not guarantee savings, and the user is responsible for verifying his/her own calculations. Rather than sending out the tool based on individual requests, the goal for 2019 is for the IDL to host the tool online when the new IDL website is launched. Once there, the tool will be available for free download by those who create an account with IDL and agree to the disclaimer. The related report for this task is located in the IDL section of *Supplement 2: Evaluation*.

Building Energy Analytics Case Study

In 2018, IDL completed the task called “Building Energy Analytics Case Study.” The purpose of this task was to identify potential savings from the implementation of a new type of energy management software focusing on building analytics. Currently, several companies promote this new type of software that monitors many control points within a building. Some examples of these analytic software packages include SkySpark, EnergyCap and BuildingIQ. These data-analysis software packages can overlay traditional Building Automation Systems (BAS) or Energy Management Systems (EMS).

The analytic software does not directly control any building equipment. Instead, its primary use is to monitor many control signals and identify potential operational problems within the building. This continuous monitoring has the potential to help maintain building commissioning and limit performance degradation through the building’s life.

IDL first identified sites that were considering the addition of an analytics system in 2018. The IDL team worked with the facility owners and control teams to document any implementation issues. The last step of the project was to identify whether the installation of the analytics software led to any operational changes and to estimate potential savings resulting from those changes.

The use of energy analytics software at the two case-study sites proved key to identifying several energy efficiency measures and equipment faults. The studies showed that the software’s full potential can be realized only when there is an existing direct digital control (DDC) system and a person dedicated to monitor the system and communicate issues to the facilities team.

The related report for this task is located in the IDL section of *Supplement 2: Evaluation*.

Measuring Indoor Performance at Educational Facilities

In 2018, IDL completed a task named Measuring Indoor Performance at Educational Facilities. The purpose of this task was to determine how effective HVAC systems are at cooling a typical secondary school classroom. IDL used the data to quantify energy savings that could be achieved through operational changes without adversely affecting occupant comfort. Four classrooms at two separate high schools were intensively monitored for several weeks. The temperature measurements from these classrooms were used to extrapolate cooling required in the schools during the spring and fall when the buildings are still using A/C. Department of Energy (DOE) prototype models of the schools were used to show how set point and scheduling adjustments to the HVAC operations could reduce peak loads and overall energy consumption at typical Idaho high schools while maintaining high environmental quality for the students.

Most classroom temperatures measured in this project fell below the recommended comfort parameters as specified by ASHRAE Standard 55. Enhancing thermal performance of the classrooms will save on unnecessary cooling and could increase student productivity. The classrooms could be brought into compliance by raising the cooling setpoint by 4 degrees Fahrenheit. This 4-degree adjustment is estimated to save an Idaho school $4 per student, 60 kWh, and 30 watts of electrical energy per student in annual energy use.

The related report for this task is located in the IDL section of *Supplement 2: Evaluation*.

2019 IDL Strategies

In 2019, IDL will continue work on the Foundational Services, Lunch & Learn sessions, BSUG, New Construction Verifications, TLL, and the Heat Pump Calculator. IDL will also provide work on two new tasks in 2019: A Building Energy Management System Predictive Control Case Study and a RTU Control Retrofits for Small Commercial Sites task.

Glossary of Acronyms

A/C—Air Conditioning/Air Conditioners

Ads—Advertisement

AEG—Applied Energy Group

AIA—American Institute of Architects

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers

B/C—Benefit/Cost

BAS—Building Automation Systems

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BOMA—Building Owners and Managers Association

BOC—Building Operator Certification

BPA—Bonneville Power Administration

BPI—Building Performance Institute

BSUG—Building Simulation Users Group

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCE—Commercial Code Enhancement

CCNO—Community Connection of Northeast Oregon, Inc.

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CFM—Cubic Feet per Minute

CHQ—Corporate Headquarters (Idaho Power)

CINA—Community in Action

CLEAResult—CLEAResult Consulting, Inc.

COP—Coefficient of Performance

CR&EE—Customer Relations and Energy Efficiency

DDC—Direct Digital Control

DEQ—Department of Environmental Quality

DHP—Ductless Heat Pump

DLC—DesignLights Consortium

DOE—Department of Energy

DSM—Demand Side Management

EA5—EA5 Energy Audit Program

ECM—Electronically Commutated Motor

EEAG—Energy Efficiency Advisory Group

EIA—U.S. Energy Information Administration

EICAP—Eastern Idaho Community Action Partnership

EISA—Energy Independence and Security Act

EL ADA—El Ada Community Action Partnership

EM&V—Evaluation, Measurement, and Verification

EMS—Energy Management Systems

EPA—Environmental Protection Agency

ESK—Energy-Saving Kit

ETO—Energy Trust of Oregon

EV—Electric Vehicle

ft—Feet

ft^2—Square Feet

ft^3—Cubic Feet

GMI—Green Motors Initiative

GMPG—Green Motors Practice Group

gpm—Gallons per Minute

H&CE—Heating & Cooling Efficiency Program

HEM-LLC—Home Energy Management, LLC.

hp—Horsepower

HPWH—Heat Pump Water Heater

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IAQ—Indoor Air Quality

IBCA—Idaho Building Contractors Association

IBCB—Idaho Building Code Board

IBOA—International Building Operators Association

ICC—International Code Council

ID—Idaho

IDHW—Idaho Department of Health and Welfare

IDL—Integrated Design Lab

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

iSTEM—Idaho Science, Technology, Engineering, and Mathematics

kW—Kilowatt

kWh—Kilowatt hour

LDL—Lighting Design Lab

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

LLLC—Luminaire Level Lighting Controls

LTMT—Long-Term Monitoring and Tracking

M&V—Measurement and Verification

MOU—Memorandum of Understanding

MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association

MW—Megawatt

MWh—Megawatt hour

MWSOC—Municipal Water Supply Optimization Cohort

n/a—Not Applicable

NAMI—National Alliance on Mental Illness

NEB—Non-Energy Benefit

NEEA—Northwest Energy Efficiency Alliance

NEEM—Northwest Energy Efficient Manufactured

NEMA—National Electrical Manufacturers Association

NPR—National Public Radio

NTG—Net to Gross

NWPCC—Northwest Power and Conservation Council

O&M—Operation and Maintenance

OPUC—Public Utility Commission of Oregon

OR—Oregon

ORS—Oregon Revised Statute

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PLC—Powerline Carrier

PPG—Program Planning Group

PSC—Permanent Split Capacitor

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAC—Residential Advisory Committee

RAP—Resource Action Programs

RBSA—Residential Building Stock Assessment

RCT—Randomized Control Trial

REEEI—Residential Energy Efficiency Education Initiative

RESNET—Residential Services Network

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure

RPAC—Regional Portfolio Advisory Committee

RPP—Retail Products Portfolio

RTF—Regional Technical Forum

RWLR—Reduced Wattage Lamp Replacement

SCCAP—South Central Community Action Partnership

SCE—Streamlined Custom Efficiency

SEEK—Students for Energy Efficiency Kit

SEICAA—Southeastern Idaho Community Action Agency

SEM—Strategic Energy Management

SIR—Savings to Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

TLL—Tool Loan Library

TRC—Total Resource Cost

TRM—Technical Reference Manual

TSV—Thermostatic Shower Valve

UCT—Utility Cost Test

UES—Unit Energy Savings

UM—Utility Miscellaneous

US—United States

USDA—United States Department of Agriculture

USGBC—US Green Building Council

VFD—Variable Frequency Drive

VHE DOAS—Very High Efficiency Dedicated Outside Air Systems

VRF—Variable Refrigerant Flow

W—Watt

WAP—Weatherization Assistance Program

WAQC—Weatherization Assistance for Qualified Customers

WHF—Whole-House Fan

WWEEC—Wastewater Energy Efficiency Cohort

XMP—Extended Motor Products

APPENDICES

Appendix 1. Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December 2018)

Idaho Energy Efficiency Rider		
2018 Beginning Balance	$	407,603
2018 Funding plus Accrued Interest as of 12-31-18		38,514,355
Total 2018 Funds		**38,921,958**
2018 Expenses as of 12-31-18		(33,663,001)
Ending Balance as of 12-31-2018	**$**	**5,258,957**
Oregon Energy Efficiency Rider		
2018 Beginning Balance	$	(6,272,529)
2018 Funds Transfer from Advice No. 18-11		5,500,000
2018 Funding plus Accrued Interest as of 12-31-18		1,132,690
Total 2018 Funds		**360,161**
2018 Expenses as of 12-31-18		(1,757,910)
Ending Balance as of 12-31-2018	**$**	**(1,397,749)**
NEEA Payments		
2018 NEEA Payments as of 12-31-2018	$	2,500,165
Total	**$**	**2,500,165**

Appendix 2. 2018 DSM expenses by funding source (dollars)

Sector/Program	Idaho Rider	Oregon Rider	Non-Rider Funds	Total
Energy Efficiency/Demand Response				
Residential				
A/C Cool Credit	$ 433,659	$ 36,425	$ 374,285	$ 844,369
Easy Savings: Low-Income Energy Efficiency Education	—	—	147,936	147,936
Educational Distributions	3,307,782	67,409	—	3,375,192
Energy Efficient Lighting	2,343,127	92,003	—	2,435,130
Energy House Calls	146,712	14,065	—	160,777
Fridge and Freezer Recycling Program	33,172	735	—	33,907
Heating & Cooling Efficiency Program	565,780	19,431	—	585,211
Home Energy Audit	264,394	—	—	264,394
Multifamily Energy Savings Program	205,131	—	—	205,131
Oregon Residential Weatherization	—	5,507	—	5,507
Rebate Advantage	105,770	41,714	—	147,483
Residential New Construction Pilot Program	400,910	2	—	400,912
Shade Tree Project	162,995	—	—	162,995
Simple Steps, Smart Savings™	86,721	3,762	—	90,484
Weatherization Assistance for Qualified Customers	—	—	1,272,973	1,272,973
Weatherization Solutions for Eligible Customers	998,233	—	24,237	1,022,471
Commercial/Industrial				
Commercial and Industrial Energy Efficiency Program...				
Custom Projects	8,400,495	395,860	12,156	8,808,512
New Construction	2,004,058	65,587	—	2,069,645
Retrofits	5,732,650	257,529	—	5,990,179
Commercial Education Initiative	144,436	1,738	—	146,174
Flex Peak Program	58,727	64,316	310,270	433,313
Irrigation				
Irrigation Efficiency Rewards	2,681,664	233,916	38,126	2,953,706
Irrigation Peak Rewards	230,953	180,865	6,479,919	6,891,737
Energy Efficiency/Demand Response Total	**$ 28,307,370**	**$ 1,480,863**	**$ 8,659,904**	**$ 38,448,137**
Market Transformation				
NEEA	2,375,157	125,008	—	2,500,165
Market Transformation Total	**$ 2,375,157**	**$ 125,008**	**$ —**	**$ 2,500,165**
Other Programs and Activities				
Commercial/Industrial Energy Efficiency Overhead	444,787	23,051	558	468,396
Energy Efficiency Direct Program Overhead	225,437	11,865	—	237,302
Home Improvement Program	2,926	—	—	2,926
Oregon Commercial Audit	—	1,473	—	1,473
Residential Energy Efficiency Education Initiative	163,255	8,961	—	172,215
Residential Energy Efficiency Overhead	1,042,132	54,125	—	1,096,257
Other Programs and Activities Total	**$ 1,878,538**	**$ 99,474**	**$ 558**	**$ 1,978,570**
Indirect Program Expenses				
Energy Efficiency Accounting & Analysis	987,281	51,254	180,706	1,219,241
Energy Efficiency Advisory Group	16,837	887	—	17,724
Special Accounting Entries	97,820	424	—	98,243
Indirect Program Expenses Total	**$ 1,101,937**	**$ 52,565**	**$ 180,706**	**$ 1,335,208**
Grand Total	**$ 33,663,001**	**$ 1,757,910**	**$ 8,841,168**	**$ 44,262,080**

Appendix 3. 2018 DSM program activity

Program	Participants		Total Costs: Utility [b]	Total Costs: Resource [c]	Savings: Annual Energy (kWh)	Savings: Peak Demand [d] (MW)	Measure Life (Years)	Nominal Levelized Costs [a]: Utility ($/kWh)	Nominal Levelized Costs [a]: Total Resource ($/kWh)
Demand Response									
A/C Cool Credit[1]	26,182	homes	$ 844,369	$ 844,369	n/a	29	n/a	n/a	n/a
Flex Peak Program[1]	140	sites	433,313	433,313	n/a	33	n/a	n/a	n/a
Irrigation Peak Rewards[1]	2,335	service points	6,891,737	6,891,737	n/a	297	n/a	n/a	n/a
Total			**$ 8,169,419**	**$ 8,169,419**		359			
Energy Efficiency									
Residential									
Easy Savings: Low-Income Energy Efficiency Education	282	HVAC tune-ups	147,936	147,936	29,610		3	1.372	1.372
Educational Distributions	94,717	kits/giveaways	3,180,380	3,180,380	16,051,888		11	0.019	0.019
Energy Efficient Lighting	1,340,842	lightbulbs	2,435,130	3,277,039	18,856,933		14	0.011	0.014
Energy House Calls	280	homes	160,777	160,777	374,484		16	0.032	0.032
Fridge and Freezer Recycling Program	304	refrigerators/freezers	33,907	33,907	73,602		7	0.061	0.061
Heating & Cooling Efficiency Program	712	projects	585,211	1,686,618	1,556,065		15	0.029	0.091
Home Energy Audit	466	audits	264,394	321,978	211,003		12	0.113	0.137
Home Energy Report Pilot Program[2]	23,914	treatment size	194,812	194,812	3,281,780		1	0.046	0.046
Multifamily Energy Savings Program	25	projects	205,131	205,131	655,953		11	0.030	0.030
Oregon Residential Weatherization	5	audits	5,507	5,507			30		
Rebate Advantage	107	homes	147,483	355,115	284,559		45	0.027	0.064
Residential New Construction Pilot	307	homes	400,912	926,958	777,369		36	0.028	0.064
Shade Tree Project	2,093	trees	162,995	162,995	35,571		20	0.307	0.307
Simple Steps, Smart Savings™	7,377	appliances/showerheads	90,484	133,101	241,215		12	0.034	0.050
Weatherization Assistance for Qualified Customers	193	homes/non-profits	1,272,973	1,819,491	649,505		30	0.111	0.159
Weatherization Solutions for Eligible Customers	141	homes	1,022,471	1,022,471	571,741		23	0.112	0.112
Sector Total			**$ 10,310,503**	**$ 13,634,216**	**43,651,278**		**13**	**$ 0.020**	**$ 0.027**
Commercial/Industrial									
Commercial Energy-Saving Kits	1,652	kits	146,174	146,174	442,170		10	0.034	0.034
Custom Projects	248	projects	8,808,512	16,112,540	46,963,690		16	0.014	0.026
Green Motors—Industrial	25	motor rewinds			64,167		7	n/a	n/a
New Construction	104	projects	2,069,645	5,054,215	13,378,315		12	0.014	0.034
Retrofits	1,358	projects	5,990,179	16,253,716	34,910,707		12	0.015	0.042
Sector Total			**$ 17,014,509**	**$ 37,566,644**	**95,759,049**		**14**	**$ 0.015**	**$ 0.032**

		Total Costs		Savings			Nominal Levelized Costs [a]	
Program	**Participants**	**Utility [b]**	**Resource [c]**	**Annual Energy (kWh)**	**Peak Demand [d] (MW)**	**Measure Life (Years)**	**Utility ($/kWh)**	**Total Resource ($/kWh)**
Irrigation								
Green Motors—Irrigation	26 motor rewinds			67,676		19	n/a	n/a
Irrigation Efficiency Reward	1,022 projects	$ 2,953,706	$ 11,948,469	18,933,831		8	$ 0.019	$ 0.076
Sector Total		**$ 2,953,706**	**$ 11,948,469**	**19,001,507**		**8**	**$ 0.019**	**$ 0.075**
Energy Efficiency Portfolio Total		**$ 30,278,718**	**$ 63,149,329**	**158,411,834**		**13**	**$ 0.016**	**$ 0.034**
Market Transformation								
Northwest Energy Efficiency Alliance (codes and standards)				21,724,800				
Northwest Energy Efficiency Alliance (other initiatives)				3,241,200				
Northwest Energy Efficiency Alliance Totals[3]		**$ 2,500,165**	**$ 2,500,165**	**24,966,000**				
Other Programs and Activities								
Residential								
Home Improvement Program		2,926	2,926					
Residential Energy Efficiency Education Initiative		172,215	172,215					
Commercial								
Oregon Commercial Audits	0 audits	1,473	1,473					
Other								
Energy Efficiency Direct Program Overhead		1,801,955	1,801,955					
Total Program Direct Expense		**$ 42,926,872**	**$ 75,797,483**	**183,377,834**	**359**			
Indirect Program Expenses		1,335,208	1,335,208					
Total DSM Expense		**$ 44,262,080**	**$ 77,132,691**					

[a] Levelized Costs are based on financial inputs from Idaho Power's 2015 IRP and calculations include line-loss adjusted energy savings.
[b] The Utility Cost is the cost incurred by Idaho Power to implement and manage a DSM program.
[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
[d] Demand response program reductions are reported with 9.7-percent peak loss assumptions.
[1] Peak Demand is the peak performance of each respective program and not combined performance on the actual system peak hour.
[2] Expenses are contained in Educational Distributions expenses in Appendix 2.
[3] Savings are preliminary estimates provided by NEEA. Final savings for 2018 will be provided by NEEA May 2019.

Appendix 4. 2018 DSM program activity by state jurisdiction

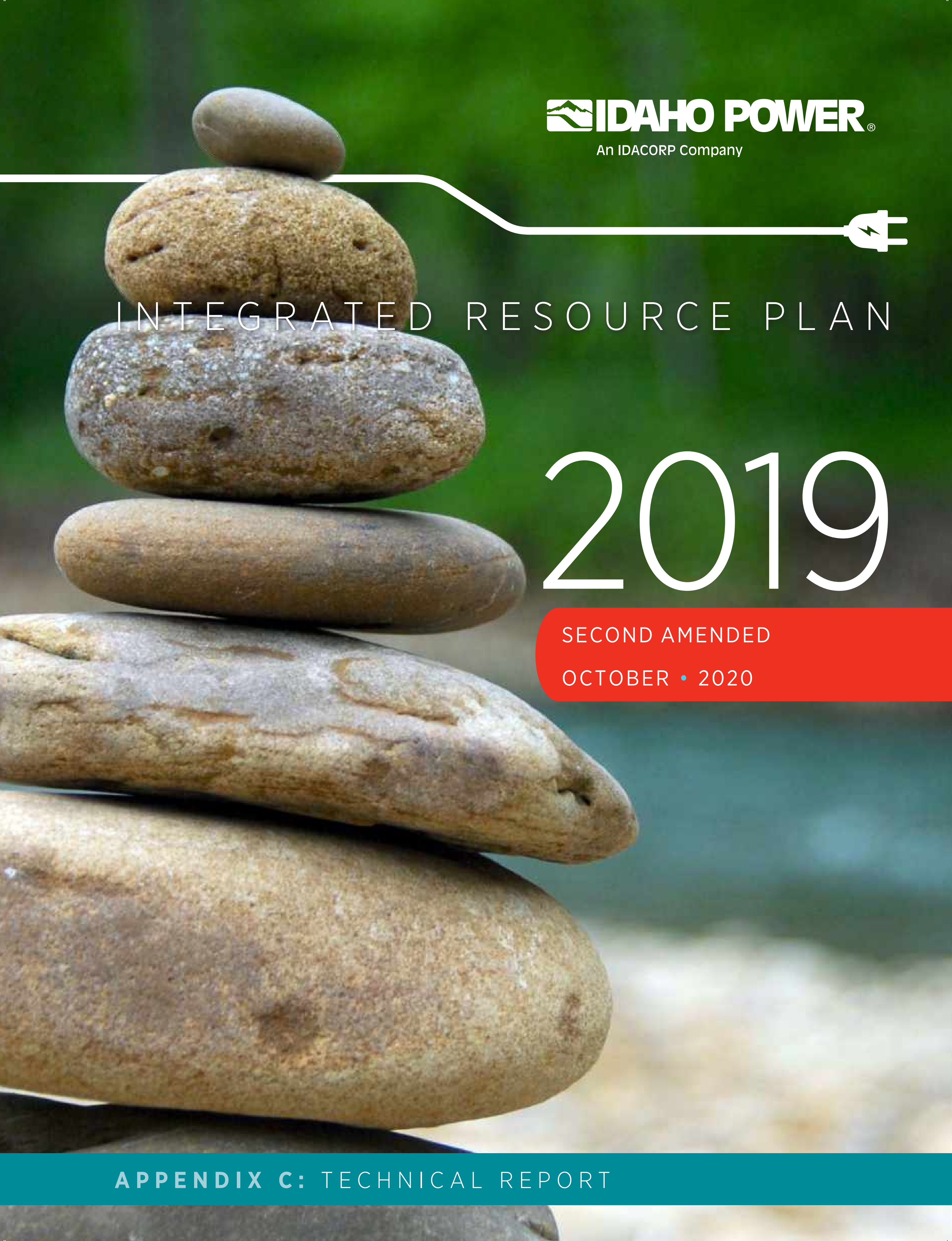
	Idaho			Oregon		
Program	Participants	Utility Costs	Demand Reduction (MW)/ Annual Energy Savings (kWh)	Participants	Utility Costs	Demand Reduction (MW)/ Annual Energy Savings (kWh)
Demand Response[1]						
A/C Cool Credit	25,845 homes	$ 807,944	29	337 homes	$ 36,425	0.4
Flex Peak Program	131 sites	368,997	31	9 sites	64,316	2
Irrigation Peak Rewards	2,285 service points	6,710,235	288	50 service points	181,502	9
Total		**$ 7,887,176**	**347**		**$ $282,243**	**12**
Energy Efficiency						
Residential						
Easy Savings: Low-Income Energy Efficiency Education	282 HVAC tune-ups	147,936	29,610	n/a		
Educational Distributions	92,996 kits/giveaways	3,112,970	15,577,291	1,721 kits/giveaways	67,409	474,596
Energy Efficient Lighting	1,291,893 lightbulbs	2,343,127	18,170,017	48,949 lightbulbs	92,003	686,916
Energy House Calls	251 homes	146,712	337,715	29 homes	14,065	36,769
Fridge and Freezer Recycling Program	298 refrigerators/freezers	33,172	71,578	6 refrigerators/freezers	735	2,025
Heating & Cooling Efficiency Program	697 projects	565,780	1,521,832	15 projects	19,431	34,234
Home Energy Audit	466 audits	264,394	211,003	n/a		
Home Energy Report Pilot Program	23,914 treatment size	194,812	3,281,780	n/a		
Multifamily Energy Savings Program [3]	25 projects	205,131	655,953	0 projects		
Oregon Residential Weatherization	n/a			5 audits	5,507	
Rebate Advantage	73 homes	105,770	205,182	34 homes	41,714	79,377
Residential New Construction Pilot	307 homes	400,910	777,369	n/a	2	
Shade Tree Project	2,093 trees	162,995	35,571	n/a		
Simple Steps, Smart Savings™	7,226 appliances/showerheads	86,721	234,664	151 appliances/showerheads	3,762	6,551
Weatherization Assistance for Qualified Customers	190 homes/non-profits	1,254,630	641,619	3 homes/non-profits	18,344	7,886
Weatherization Solutions for Eligible Customers	141 homes	1,022,471	571,741	n/a		
Sector Total		**$ 10,047,532**	**42,322,925**		**$ 262,971**	**1,328,353**
Commercial						
Commercial Energy-Saving Kits	1,621 kits	144,436	433,961	31 kits	1,738	8,209
Custom Projects	238 projects	8,412,044	45,663,289	10 projects	396,468	1,300,401
Green Motors—Industrial	25 motor rewinds		64,167	0 motor rewinds		
New Construction	99 projects	2,004,058	13,092,349	5 projects	65,587	285,966
Retrofits	1,322 projects	5,732,650	33,483,180	36 projects	257,529	1,427,527
Sector Total		**$ 16,293,187**	**92,736,946**		**$ 721,322**	**3,022,103**

Program	Idaho Participants	Idaho Utility Costs	Idaho Demand Reduction (MW)/ Annual Energy Savings (kWh)	Oregon Participants	Oregon Utility Costs	Oregon Demand Reduction (MW)/ Annual Energy Savings (kWh)
Irrigation						
Green Motors—Irrigation	26 motor rewinds		67,676	0 motor rewind		
Irrigation Efficiency Rewards	971 projects	$ 2,717,884	18,000,390	51 projects	$ 235,822	933,441
Sector Total		**$ 2,717,884**	**18,068,066**		**$ 235,822**	**933,441**
Market Transformation						
Northwest Energy Efficiency Alliance (codes and standards)			20,638,560			1,086,240
Northwest Energy Efficiency Alliance (other initiatives)			3,079,140			162,060
Northwest Energy Efficiency Alliance[2]		**$ 2,375,157**	**23,717,700**		**$ 125,008**	**1,248,300**
Other Programs and Activities						
Residential						
Home Improvement Program		2,926				
Residential Energy Efficiency Education Initiative		163,255			8,961	
Commercial						
Oregon Commercial Audits					1,473	
Other						
Energy Efficiency Direct Program Overhead		1,712,887			89,069	
Total Program Direct Expense		**$ 41,200,004**			**$ 1,726,868**	
Indirect Program Expenses		1,273,608			61,600	
Total Annual Savings			**176,845,637**			**6,532,197**
Total DSM Expense		**$ 42,473,612**			**$ 1,788,468**	

[1] Peak Demand is the peak performance of each respective program and not combined performance on the actual system peak hour.

[2] Savings are preliminary estimates provided by NEEA. Final savings for 2018 will be provided by NEEA May 2019.

[3] Idaho Rider charges of $13,264 were reversed and charged to the Oregon Rider in March 2019. Oregon savings should have been 67,270 kWh.



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INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED

OCTOBER • 2020

APPENDIX C: TECHNICAL REPORT

SAFE HARBOR STATEMENT

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

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INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2019 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2019 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2018 Annual Report*, and supplemental information on Boardman to Hemingway (B2H) transmission is provided in *Appendix D–B2H Supplement.* The IRP, including the four appendices, was filed with the Idaho and Oregon public utility commissions in June 2019. Amendments to the IRP, *Appendix C—Technical Appendix* and *Appendix D—B2H Supplement* were filed with the Idaho and Oregon public utility commissions in January 2020.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2706

irp@idahopower.com

IRP ADVISORY COUNCIL

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted 10 IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is rewarding, and the IRP is better because of public involvement. Idaho Power and the members of the IRPAC recognize outside perspective is valuable, but also understand that final decisions on the IRP are made by Idaho Power.

Customer Representatives

Agricultural Representative	Sid Erwin
Boise State University	Barry Burbank
Idaho National Laboratory	Kurt Myers
Micron	Clancy Kelley
St. Luke's Medical	Mark Eriksen

Public-Interest Representatives

Boise Metro Chamber of Commerce	Ray Stark
Boise State University Energy Policy Institute	Kathleen Araujo
City of Boise	Steve Burgos
Idaho Conservation League	Ben Otto
Idaho Legislature	Representative Robert Anderst
Idaho Office of Energy and Mineral Resources	John Chatburn
Idaho Sierra Club	Mike Heckler
Idaho Technology Council	Jay Larsen
Idaho Water Resource Board	Roger Chase
Northwest Power and Conservation Council	Ben Kujala
Oil and Gas Industry Advisor	David Hawk
Oregon State University—Malheur Experiment Station	Clint Shock
Snake River Alliance	Chad Worth

Regulatory Commission Representatives

Idaho Public Utilities Commission	Stacey Donohue
Public Utility Commission of Oregon	Nadine Hanhan

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2018	Thursday, September 13	Welcome and opening remarks 2017 IRP Review IRP overview and process road map Carbon Outlook Natural gas forecast
2018	Thursday, October 11	IRP process review Load forecast Streamflow forecast Hydro production forecast Hydro climate change modeling results PURPA forecast and assumptions Natural gas price
2018	Thursday, November 8	Regional transmission overview Boardman to Hemingway transmission update Storage outlook Resource cost assumptions IPC planning criteria capacity, energy, and flexibility—2017 IRP to 2019 IRP Coal unit futures
2018	Thursday, December 13	AURORA model workshop Energy efficiency potential study Regional resource adequacy Solar capacity credit Distributed resources: value to the transmission and distribution system
2019	Thursday, January 10	T&D deferral benefit Demand response Energy imbalance market (EIM) Reserve requirements Capacity expansion modeling update Updated resource cost assumptions
2019	Thursday, March 14	AURORA LTCE portfolio results Sensitivities to planning assumptions Stochastic elements Hells Canyon Complex relicensing Cloud seeding
2019	Thursday, April 11	Idaho Power clean energy goal AURORA results update Qualitative risk assessment Preliminary preferred portfolio recommendation
2019	Thursday, May 9	Loss of load analysis Power system operations: summer readiness IPC sustainability programs 2019 IRP action plan

Meeting Dates		Agenda Items
2019	Thursday, September 18	Review Initial Conclusions Cause for Supplemental Analysis Modeling Updates Next Steps
2019	Friday, December 6	Discount Rate Change Other Updates and Modeling Assumptions Modeling Results 2019 Preferred Portfolio and Action Plan

Sales and Load Forecast Data

50th Percentile Annual Forecast Growth Rates

	2019–2024	2019–2029	2019–2038
Sales			
Residential Sales	1.17%	1.15%	1.13%
Commercial Sales	1.17%	1.21%	1.15%
Irrigation Sales	0.78%	0.76%	0.75%
Industrial Sales	1.09%	0.82%	0.56%
Additional Firm Sales	3.68%	2.06%	1.18%
System Sales	1.27%	1.12%	1.00%
Total Sales	1.27%	1.12%	1.00%
Loads			
Residential Load	1.11%	1.15%	1.13%
Commercial Load	1.12%	1.21%	1.14%
Irrigation Load	0.72%	0.76%	0.75%
Industrial Load	1.02%	0.81%	0.55%
Additional Firm Sales	3.68%	2.06%	1.18%
System Load Losses	1.12%	1.10%	1.02%
System Load	1.21%	1.12%	1.00%
Total Load	1.21%	1.12%	1.00%
Peaks			
System Peak	1.35%	1.27%	1.18%
Total Peak	1.35%	1.27%	1.18%
Winter Peak	1.14%	1.03%	0.95%
Summer Peak	1.35%	1.27%	1.18%
Customers			
Residential Customers	2.12%	1.93%	1.68%
Commercial Customers	1.97%	1.80%	1.67%
Irrigation Customers	1.32%	1.28%	1.21%
Industrial Customers	0.53%	0.43%	0.49%

Expected-Case Load Forecast

2019 Monthly Summary[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	831	711	575	502	442	530	649	605	474	487	625	786
Commercial	505	482	443	429	437	482	501	509	463	454	462	513
Irrigation	3	3	8	119	324	624	631	546	316	67	5	3
Industrial	274	280	281	270	274	294	288	296	288	291	283	282
Additional Firm	114	114	108	104	104	95	105	107	111	112	118	120
Loss	147	134	117	119	134	176	190	179	139	116	124	144
System Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Light Load	1,750	1,587	1,406	1,398	1,558	1,991	2,133	1,986	1,616	1,368	1,489	1,712
Heavy Load	1,972	1,826	1,631	1,648	1,837	2,369	2,545	2,429	1,945	1,642	1,720	1,966
Total Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,502	2,277	2,030	2,000	2,675	3,470	3,610	3,354	2,795	2,070	2,277	2,549
System Peak Load (1 hour) 95th Percentile	2,535	2,361	2,075	2,015	2,695	3,511	3,634	3,391	2,812	2,087	2,319	2,636

2020 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	842	695	581	506	445	535	657	613	478	490	629	794
Commercial	513	472	448	434	442	488	508	516	469	459	467	518
Irrigation	3	2	8	120	328	630	638	551	319	68	5	3
Industrial	278	274	284	273	277	298	292	300	292	294	287	287
Additional Firm	117	112	110	106	106	97	106	109	113	114	120	123
Loss	149	131	119	120	135	178	192	181	141	117	125	146
System Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Light Load	1,775	1,553	1,422	1,414	1,575	2,013	2,160	2,011	1,633	1,382	1,504	1,733
Heavy Load	2,000	1,785	1,649	1,667	1,869	2,381	2,577	2,476	1,952	1,658	1,747	1,980
Total Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,522	2,298	2,034	2,017	2,693	3,527	3,659	3,407	2,829	2,087	2,295	2,581
System Peak Load (1 hour) 95th Percentile	2,555	2,382	2,080	2,032	2,713	3,568	3,683	3,444	2,846	2,105	2,337	2,668

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

2021 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	853	730	586	510	448	540	665	620	481	492	633	802
Commercial	518	493	451	439	446	493	513	522	473	462	471	524
Irrigation	3	3	8	121	330	634	642	555	321	68	5	3
Industrial	282	288	288	277	281	302	296	304	296	299	291	289
Additional Firm	121	120	114	110	110	101	111	113	117	119	125	127
Loss	151	137	120	121	136	180	194	183	142	118	126	148
System Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Light Load	1,801	1,631	1,439	1,430	1,592	2,034	2,185	2,035	1,650	1,396	1,520	1,754
Heavy Load	2,038	1,876	1,660	1,685	1,888	2,406	2,607	2,506	1,973	1,686	1,756	2,004
Total Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,555	2,322	2,060	2,032	2,710	3,558	3,707	3,450	2,860	2,105	2,312	2,597
System Peak Load (1 hour) 95th Percentile	2,588	2,406	2,106	2,047	2,730	3,600	3,731	3,487	2,877	2,123	2,354	2,684

2022 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	864	738	590	513	451	545	674	629	486	496	639	812
Commercial	527	500	457	445	452	499	521	530	478	468	477	531
Irrigation	3	3	8	122	333	640	647	560	324	69	5	3
Industrial	284	290	291	280	283	305	299	307	298	301	293	292
Additional Firm	125	124	118	114	114	105	114	117	121	123	129	131
Loss	153	139	121	123	138	182	197	185	144	120	128	149
System Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Light Load	1,826	1,653	1,455	1,446	1,609	2,058	2,214	2,062	1,670	1,413	1,538	1,777
Heavy Load	2,067	1,901	1,679	1,704	1,909	2,434	2,659	2,522	1,997	1,706	1,778	2,031
Total Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,554	2,346	2,080	2,048	2,728	3,609	3,757	3,506	2,897	2,125	2,332	2,625
System Peak Load (1 hour) 95th Percentile	2,617	2,430	2,125	2,063	2,749	3,650	3,782	3,544	2,914	2,143	2,374	2,712

2023 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	878	749	598	519	457	554	687	640	492	501	646	822
Commercial	534	506	462	450	457	505	528	537	483	473	482	537
Irrigation	3	3	8	123	336	645	653	565	326	69	5	3
Industrial	287	293	293	282	286	308	302	310	301	304	296	295
Additional Firm	127	126	120	116	116	107	117	120	124	125	131	134
Loss	156	141	123	124	139	184	199	188	145	121	129	151
System Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Light Load	1,852	1,675	1,472	1,463	1,627	2,083	2,243	2,089	1,689	1,428	1,555	1,799
Heavy Load	2,097	1,927	1,699	1,735	1,919	2,463	2,693	2,555	2,019	1,724	1,797	2,065
Total Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,611	2,369	2,097	2,064	2,747	3,654	3,808	3,559	2,932	2,144	2,350	2,648
System Peak Load (1 hour) 95th Percentile	2,644	2,453	2,143	2,079	2,767	3,696	3,832	3,596	2,949	2,161	2,392	2,735

2024 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	891	734	605	525	462	562	698	650	498	505	652	832
Commercial	540	494	466	455	461	510	534	544	488	477	486	543
Irrigation	3	3	8	124	338	650	658	569	329	70	5	3
Industrial	290	286	296	285	289	311	304	313	304	307	299	297
Additional Firm	138	132	130	124	124	115	124	127	131	134	141	145
Loss	158	138	124	126	141	186	202	190	147	122	131	153
System Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Light Load	1,886	1,646	1,495	1,484	1,650	2,111	2,275	2,119	1,711	1,447	1,578	1,827
Heavy Load	2,125	1,892	1,735	1,750	1,945	2,512	2,715	2,592	2,059	1,736	1,824	2,098
Total Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,650	2,400	2,125	2,087	2,771	3,706	3,863	3,617	2,971	2,167	2,376	2,682
System Peak Load (1 hour) 95th Percentile	2,683	2,484	2,171	2,102	2,791	3,748	3,887	3,655	2,988	2,185	2,418	2,768

2025 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	903	771	611	530	467	569	710	660	503	509	657	840
Commercial	548	519	472	461	467	517	541	551	493	482	492	550
Irrigation	3	3	8	125	341	655	663	573	331	70	5	3
Industrial	292	298	298	287	291	313	307	315	306	309	301	298
Additional Firm	140	139	132	126	125	116	125	128	132	135	143	147
Loss	160	145	125	127	142	188	204	192	148	123	132	155
System Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Light Load	1,911	1,727	1,511	1,499	1,666	2,133	2,302	2,144	1,727	1,460	1,593	1,846
Heavy Load	2,154	1,986	1,753	1,768	1,965	2,538	2,746	2,640	2,065	1,752	1,851	2,109
Total Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,679	2,426	2,144	2,101	2,787	3,753	3,911	3,670	3,003	2,184	2,392	2,705
System Peak Load (1 hour) 95th Percentile	2,711	2,510	2,190	2,116	2,808	3,795	3,935	3,707	3,020	2,201	2,435	2,791

2026 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	914	779	616	534	471	575	719	669	507	511	661	847
Commercial	556	526	477	466	472	523	549	559	499	487	497	556
Irrigation	3	3	8	126	343	660	668	578	334	71	5	3
Industrial	293	300	300	288	292	315	308	317	308	311	303	300
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	162	147	126	128	144	190	207	195	150	124	133	156
System Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Light Load	1,932	1,744	1,523	1,512	1,680	2,152	2,325	2,165	1,741	1,470	1,605	1,862
Heavy Load	2,177	2,006	1,767	1,782	1,993	2,545	2,775	2,667	2,082	1,764	1,865	2,128
Total Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,699	2,443	2,154	2,113	2,801	3,786	3,956	3,712	3,030	2,196	2,404	2,717
System Peak Load (1 hour) 95th Percentile	2,732	2,527	2,200	2,128	2,821	3,827	3,980	3,749	3,047	2,214	2,446	2,804

2027 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	924	787	621	537	474	581	728	677	511	513	664	856
Commercial	564	532	482	472	477	529	556	567	504	492	503	563
Irrigation	3	3	8	127	346	666	674	583	337	72	5	3
Industrial	295	301	302	290	294	317	310	319	310	313	305	302
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	164	148	128	129	145	191	209	197	151	125	134	158
System Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Light Load	1,952	1,761	1,535	1,524	1,693	2,172	2,349	2,187	1,755	1,480	1,616	1,880
Heavy Load	2,210	2,025	1,772	1,796	2,009	2,568	2,803	2,693	2,098	1,787	1,867	2,148
Total Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,721	2,460	2,166	2,124	2,814	3,826	4,001	3,759	3,057	2,208	2,416	2,736
System Peak Load (1 hour) 95th Percentile	2,753	2,544	2,212	2,139	2,835	3,867	4,026	3,796	3,074	2,226	2,458	2,823

2028 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	937	771	627	542	479	588	740	687	516	517	670	866
Commercial	572	520	487	478	483	536	564	575	510	498	508	570
Irrigation	3	3	9	128	349	671	679	587	339	72	5	3
Industrial	297	292	303	292	295	318	312	320	311	314	306	303
Additional Firm	141	136	133	127	126	117	126	129	134	136	145	148
Loss	166	145	129	130	146	193	211	199	152	126	135	160
System Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Light Load	1,976	1,719	1,549	1,537	1,708	2,192	2,375	2,211	1,770	1,491	1,629	1,900
Heavy Load	2,236	1,976	1,788	1,823	2,014	2,593	2,852	2,704	2,116	1,800	1,882	2,181
Total Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,747	2,480	2,183	2,137	2,829	3,874	4,048	3,812	3,087	2,222	2,430	2,761
System Peak Load (1 hour) 95th Percentile	2,780	2,564	2,229	2,152	2,849	3,916	4,073	3,849	3,104	2,240	2,472	2,848

2029 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	952	810	635	548	484	597	752	698	522	522	676	875
Commercial	581	546	493	484	489	543	572	583	516	503	514	578
Irrigation	3	3	9	129	352	676	684	592	342	73	5	3
Industrial	298	304	304	293	297	319	313	322	313	316	307	304
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	168	152	130	132	147	195	214	201	154	127	136	161
System Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Light Load	2,001	1,802	1,564	1,552	1,723	2,214	2,402	2,236	1,786	1,503	1,643	1,918
Heavy Load	2,255	2,072	1,805	1,840	2,032	2,618	2,885	2,734	2,150	1,803	1,898	2,202
Total Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,777	2,505	2,203	2,151	2,844	3,928	4,097	3,869	3,119	2,237	2,444	2,786
System Peak Load (1 hour) 95th Percentile	2,809	2,589	2,249	2,166	2,865	3,970	4,121	3,906	3,136	2,255	2,487	2,873

2030 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	963	820	640	552	488	602	762	706	526	524	680	884
Commercial	590	554	499	491	495	550	580	592	522	509	521	585
Irrigation	3	3	9	130	355	682	690	597	345	73	5	3
Industrial	299	305	305	294	298	320	314	323	314	317	308	305
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	170	154	131	133	149	197	216	203	155	128	137	163
System Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Light Load	2,023	1,820	1,576	1,564	1,737	2,234	2,427	2,258	1,800	1,513	1,654	1,935
Heavy Load	2,280	2,093	1,829	1,844	2,048	2,658	2,895	2,762	2,167	1,815	1,912	2,222
Total Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,799	2,524	2,215	2,163	2,858	3,966	4,143	3,915	3,147	2,250	2,457	2,803
System Peak Load (1 hour) 95th Percentile	2,832	2,608	2,261	2,178	2,878	4,008	4,167	3,953	3,164	2,268	2,499	2,890

2031 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	975	829	645	555	491	608	772	715	530	526	684	892
Commercial	598	561	505	497	501	556	588	600	528	515	526	593
Irrigation	3	3	9	131	357	687	695	601	347	74	5	3
Industrial	300	306	307	295	299	322	315	324	315	318	310	306
Additional Firm	142	141	134	128	127	118	127	130	134	137	145	149
Loss	172	155	132	134	150	199	218	205	156	129	138	164
System Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Light Load	2,046	1,838	1,589	1,576	1,750	2,253	2,451	2,281	1,814	1,523	1,666	1,952
Heavy Load	2,295	2,114	1,843	1,858	2,052	2,681	2,907	2,809	2,155	1,827	1,925	2,220
Total Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,826	2,545	2,233	2,174	2,871	4,019	4,189	3,971	3,174	2,262	2,469	2,828
System Peak Load (1 hour) 95th Percentile	2,859	2,629	2,278	2,189	2,892	4,060	4,213	4,008	3,191	2,280	2,511	2,915

2032 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	987	810	650	559	495	614	782	724	534	529	688	899
Commercial	607	549	510	503	507	563	596	608	534	520	532	599
Irrigation	3	3	9	132	360	692	700	606	350	74	5	3
Industrial	301	297	308	296	300	323	316	325	316	319	311	307
Additional Firm	142	137	134	128	127	118	127	130	135	138	146	150
Loss	174	151	133	135	151	201	221	208	158	130	139	166
System Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Light Load	2,068	1,792	1,601	1,588	1,763	2,271	2,475	2,303	1,827	1,532	1,677	1,967
Heavy Load	2,320	2,071	1,847	1,872	2,079	2,686	2,935	2,836	2,171	1,850	1,927	2,237
Total Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,849	2,559	2,245	2,185	2,884	4,057	4,234	4,017	3,201	2,274	2,480	2,844
System Peak Load (1 hour) 95th Percentile	2,882	2,644	2,290	2,200	2,905	4,099	4,258	4,054	3,218	2,292	2,522	2,930

2033 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	996	846	653	560	496	618	790	731	536	529	690	906
Commercial	615	575	515	509	512	569	603	616	539	525	538	606
Irrigation	3	3	9	133	363	697	706	610	353	75	5	3
Industrial	302	308	309	297	301	324	317	326	317	320	312	308
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	176	158	134	136	152	202	223	209	159	130	140	167
System Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Light Load	2,087	1,872	1,610	1,597	1,774	2,288	2,496	2,323	1,839	1,539	1,685	1,982
Heavy Load	2,352	2,153	1,859	1,883	2,092	2,706	2,979	2,841	2,184	1,859	1,937	2,254
Total Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,870	2,579	2,255	2,195	2,895	4,096	4,277	4,062	3,224	2,283	2,489	2,860
System Peak Load (1 hour) 95th Percentile	2,902	2,664	2,301	2,210	2,916	4,137	4,301	4,099	3,241	2,301	2,532	2,947

2034 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,008	856	659	564	501	625	801	741	541	533	695	916
Commercial	622	581	520	514	517	575	610	623	544	530	542	612
Irrigation	3	3	9	134	365	703	711	615	355	76	5	3
Industrial	303	309	310	298	302	325	318	327	318	321	313	309
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	178	160	135	137	153	204	225	212	160	131	141	169
System Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Light Load	2,108	1,889	1,622	1,609	1,787	2,307	2,522	2,346	1,853	1,549	1,697	1,999
Heavy Load	2,375	2,172	1,871	1,908	2,095	2,729	3,009	2,869	2,201	1,871	1,951	2,284
Total Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,893	2,598	2,269	2,205	2,908	4,142	4,324	4,114	3,252	2,296	2,502	2,882
System Peak Load (1 hour) 95th Percentile	2,926	2,682	2,315	2,220	2,928	4,184	4,348	4,151	3,269	2,314	2,544	2,969

2035 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,022	868	667	571	507	635	816	754	548	538	702	927
Commercial	630	587	525	519	521	581	617	630	549	534	547	618
Irrigation	3	3	9	135	368	708	717	620	358	76	6	3
Industrial	304	310	310	299	303	326	319	328	319	322	313	309
Additional Firm	143	142	135	129	128	119	128	131	136	139	147	150
Loss	180	162	136	138	155	206	227	214	161	132	142	170
System Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Light Load	2,131	1,908	1,635	1,622	1,802	2,329	2,549	2,371	1,868	1,560	1,709	2,017
Heavy Load	2,391	2,194	1,887	1,924	2,113	2,755	3,041	2,899	2,233	1,872	1,965	2,305
Total Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,919	2,619	2,286	2,218	2,923	4,192	4,372	4,168	3,281	2,309	2,515	2,905
System Peak Load (1 hour) 95th Percentile	2,952	2,703	2,331	2,233	2,943	4,233	4,397	4,206	3,298	2,327	2,557	2,992

2036 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,038	851	675	579	514	646	832	768	555	543	709	938
Commercial	637	572	529	524	526	586	624	637	553	538	552	624
Irrigation	3	3	9	136	371	714	722	625	361	77	6	3
Industrial	304	300	311	299	303	326	320	329	319	322	314	310
Additional Firm	144	138	135	129	129	120	129	132	136	139	147	151
Loss	182	158	138	139	156	208	230	216	163	133	143	172
System Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Light Load	2,155	1,862	1,649	1,637	1,817	2,352	2,577	2,396	1,883	1,570	1,722	2,036
Heavy Load	2,418	2,139	1,913	1,929	2,131	2,798	3,057	2,951	2,237	1,884	1,990	2,315
Total Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,948	2,638	2,304	2,232	2,939	4,247	4,422	4,226	3,312	2,322	2,528	2,931
System Peak Load (1 hour) 95th Percentile	2,980	2,722	2,350	2,247	2,959	4,288	4,446	4,264	3,329	2,340	2,570	3,018

2037 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,053	894	684	586	522	657	847	781	563	548	716	949
Commercial	644	599	533	529	531	591	630	644	557	542	556	629
Irrigation	3	3	9	137	374	719	728	630	364	77	6	3
Industrial	305	311	311	300	304	327	320	329	320	323	314	310
Additional Firm	144	143	135	129	129	120	129	132	136	139	147	151
Loss	184	165	139	141	158	210	233	219	164	134	145	173
System Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Light Load	2,179	1,948	1,662	1,650	1,833	2,374	2,605	2,421	1,898	1,581	1,734	2,052
Heavy Load	2,445	2,240	1,928	1,945	2,161	2,807	3,090	2,982	2,255	1,897	2,004	2,334
Total Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,974	2,662	2,320	2,245	2,954	4,295	4,471	4,280	3,341	2,335	2,540	2,951
System Peak Load (1 hour) 95th Percentile	3,006	2,747	2,366	2,260	2,974	4,336	4,495	4,317	3,358	2,353	2,583	3,038

2038 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,068	906	691	593	528	667	862	794	569	553	722	959
Commercial	650	604	537	533	534	596	636	650	561	546	560	633
Irrigation	3	3	9	138	377	725	734	635	367	78	6	4
Industrial	305	311	312	300	304	327	321	330	320	323	315	311
Additional Firm	144	143	135	129	129	120	129	132	137	140	148	151
Loss	186	167	140	142	159	212	235	221	165	135	146	175
System Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Light Load	2,201	1,966	1,675	1,663	1,847	2,395	2,632	2,445	1,912	1,590	1,744	2,069
Heavy Load	2,480	2,261	1,933	1,960	2,178	2,832	3,122	3,011	2,271	1,920	2,005	2,352
Total Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,998	2,682	2,334	2,257	2,968	4,341	4,519	4,332	3,369	2,347	2,552	2,971
System Peak Load (1 hour) 95th Percentile	3,031	2,766	2,380	2,272	2,988	4,382	4,544	4,369	3,386	2,364	2,594	3,058

Annual Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Billed Sales (MWh) 70th Percentile										
Residential	5,437,937	5,493,644	5,547,973	5,608,333	5,688,441	5,763,194	5,834,023	5,890,805	5,944,148	6,014,532
Commercial	4,196,788	4,251,251	4,291,921	4,350,949	4,401,332	4,448,900	4,505,483	4,562,301	4,615,732	4,674,083
Irrigation	2,074,146	2,093,175	2,106,818	2,123,833	2,140,578	2,156,322	2,171,522	2,187,603	2,204,350	2,221,073
Industrial	2,481,792	2,510,977	2,547,534	2,570,263	2,595,285	2,619,587	2,638,463	2,652,628	2,669,207	2,681,291
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Load	15,147,362	15,326,046	15,507,246	15,701,378	15,894,635	16,134,002	16,310,491	16,457,337	16,600,437	16,761,979
Total Load	**15,147,362**	**15,326,046**	**15,507,246**	**15,701,378**	**15,894,635**	**16,134,002**	**16,310,491**	**16,457,337**	**16,600,437**	**16,761,979**
Generation Month Sales (MWh) 70th Percentile										
Residential	5,442,618	5,498,804	5,552,533	5,614,209	5,693,977	5,768,505	5,838,363	5,894,961	5,949,634	6,020,876
Commercial	4,200,298	4,253,908	4,295,719	4,354,214	4,404,424	4,452,555	4,509,159	4,565,769	4,619,509	4,678,039
Irrigation	2,074,158	2,093,183	2,106,828	2,123,843	2,140,588	2,156,331	2,171,532	2,187,613	2,204,360	2,221,083
Industrial	2,484,235	2,514,036	2,549,437	2,572,357	2,597,319	2,621,167	2,639,649	2,654,015	2,670,219	2,682,204
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Total Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Loss	1,290,909	1,305,542	1,319,389	1,335,058	1,351,249	1,368,458	1,383,403	1,396,552	1,409,433	1,424,125
Required Generation	**16,448,918**	**16,642,475**	**16,836,907**	**17,047,681**	**17,256,557**	**17,513,016**	**17,703,106**	**17,862,910**	**18,020,155**	**18,197,327**
Average Load (aMW) 70th Percentile										
Residential	621	626	634	641	650	657	666	673	679	685
Commercial	479	484	490	497	503	507	515	521	527	533
Irrigation	237	238	241	242	244	245	248	250	252	253
Industrial	284	286	291	294	296	298	301	303	305	305
Additional Firm	109	111	116	120	122	130	133	133	133	133
Loss	147	149	151	152	154	156	158	159	161	162
System Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Light Load	1,708	1,723	1,748	1,770	1,792	1,814	1,838	1,855	1,871	1,885
Heavy Load	2,010	2,029	2,058	2,084	2,110	2,134	2,164	2,183	2,203	2,219
Total Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	3,634	3,683	3,731	3,782	3,832	3,887	3,935	3,980	4,026	4,073
Total Peak Load	**3,634**	**3,683**	**3,731**	**3,782**	**3,832**	**3,887**	**3,935**	**3,980**	**4,026**	**4,073**

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Billed Sales (MWh) 70th Percentile										
Residential	6,095,509	6,152,545	6,212,850	6,269,841	6,312,160	6,378,952	6,464,432	6,557,678	6,648,731	6,734,413
Commercial	4,735,240	4,799,479	4,857,014	4,919,215	4,972,567	5,023,928	5,074,557	5,123,093	5,170,831	5,211,986
Irrigation	2,237,536	2,254,044	2,270,422	2,286,620	2,303,006	2,319,804	2,336,631	2,353,973	2,371,564	2,389,219
Industrial	2,692,197	2,700,947	2,713,441	2,720,965	2,731,480	2,739,017	2,745,330	2,750,321	2,754,092	2,758,211
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Total Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Generation Month Sales (MWh) 70th Percentile										
Residential	6,100,167	6,157,528	6,217,678	6,273,685	6,316,791	6,384,855	6,470,892	6,563,965	6,654,615	6,740,060
Commercial	4,739,391	4,803,216	4,861,046	4,922,698	4,975,928	5,027,246	5,077,747	5,126,236	5,173,564	5,214,450
Irrigation	2,237,546	2,254,054	2,270,432	2,286,630	2,303,016	2,319,814	2,336,642	2,353,984	2,371,575	2,389,230
Industrial	2,692,929	2,701,993	2,714,070	2,721,845	2,732,111	2,739,546	2,745,748	2,750,637	2,754,437	2,758,943
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Total Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Loss	1,439,675	1,453,295	1,466,761	1,479,909	1,491,254	1,504,694	1,519,675	1,535,160	1,550,227	1,564,294
Required Generation	**18,382,709**	**18,546,087**	**18,707,987**	**18,864,766**	**19,002,100**	**19,162,154**	**19,338,704**	**19,520,980**	**19,697,417**	**19,862,977**
Average Load (aMW) 70th Percentile										
Residential	696	703	710	714	721	729	739	747	760	769
Commercial	541	548	555	560	568	574	580	584	591	595
Irrigation	255	257	259	260	263	265	267	268	271	273
Industrial	307	308	310	310	312	313	313	313	314	315
Additional Firm	134	134	134	134	135	135	136	136	136	137
Loss	164	166	167	168	170	172	173	175	177	179
System Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Light Load	1,909	1,926	1,943	1,954	1,973	1,990	2,008	2,022	2,046	2,063
Heavy Load	2,247	2,267	2,281	2,293	2,316	2,336	2,357	2,373	2,401	2,421
Total Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544
Total Peak Load	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544

DEMAND-SIDE RESOURCE DATA

DSM Financial Assumptions

Avoided Levelized Capacity Costs	
Reciprocating Internal Combustion Engine (RICE)	$121.19/kW-year
Financial Assumptions	
Discount rate (weighted average cost of capital)	7.12%
Financial escalation factor	2.20%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Avoided Cost Averages ($/MWh except where noted)

Year	Summer On-Peak[1]	Summer Mid-Peak	Summer Off-Peak	Non-Summer Mid-Peak	Non-Summer Off-Peak	Annual Average[2]	Annual T&D On-Peak Deferral Value ($/kW-year)
2019	$44.25	$30.93	$27.15	$27.62	$23.11	$42.64	$6.52
2020	$47.17	$30.09	$26.65	$27.89	$23.04	$42.48	$4.10
2021	$50.02	$32.14	$28.38	$28.85	$24.22	$43.84	$4.10
2022	$52.88	$32.97	$28.97	$29.62	$25.35	$44.84	$4.10
2023	$54.91	$34.45	$29.94	$30.49	$26.42	$45.90	$3.99
2024	$56.78	$36.59	$32.11	$32.88	$27.97	$47.87	$3.99
2025	$58.50	$38.44	$33.77	$34.49	$29.61	$49.57	$3.84
2026	$60.06	$36.45	$29.23	$35.82	$28.36	$49.27	$3.94
2027	$61.46	$38.80	$32.47	$38.86	$31.27	$52.10	$4.10
2028	$62.79	$42.29	$35.52	$40.54	$33.90	$54.32	$4.22
2029	$64.09	$43.66	$39.51	$42.43	$36.96	$56.75	$4.28
2030	$65.39	$44.72	$38.76	$42.36	$36.83	$56.79	$4.22
2031	$66.67	$47.61	$42.11	$45.57	$39.65	$59.75	$4.28
2032	$67.95	$48.68	$43.86	$47.19	$41.24	$61.26	$4.28
2033	$69.24	$49.94	$44.90	$48.55	$42.85	$62.70	$4.28
2034	$70.55	$51.39	$46.69	$50.04	$44.42	$64.01	$2.49
2035	$71.90	$52.98	$47.92	$52.00	$45.97	$65.72	$2.67
2036	$73.27	$55.74	$49.99	$54.04	$47.63	$67.63	$2.59
2037	$74.88	$56.50	$52.01	$56.40	$49.00	$69.35	$1.40
2038	$76.53	$55.18	$52.09	$55.50	$49.35	$69.04	$1.49

[1] Estimated average annual variable operations and management costs of a 111 MW-capacity RICE unit.

[2] Annual average across all hours includes avoided capacity value of $121.19 kW-year from a 111 MW RICE unit applied across Summer On-Peak hours.

Bundle Amounts

Cumulative Achievable Potential (aMW)

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	1	3	4	6	7	9	11	13	15	17
10-20th Percentile	3	3	5	6	8	10	11	13	15	17
20-30th Percentile	3	5	7	9	12	14	16	18	20	22
30-40th Percentile	1	3	5	6	8	10	12	14	16	18
40-50th Percentile	2	3	5	6	8	10	11	13	14	16
50-60th Percentile	1	3	4	6	7	8	10	11	13	14
60-70th Percentile	2	4	6	9	11	13	15	17	19	21
70-80th Percentile	3	6	10	13	16	19	21	23	25	27
80-90th Percentile	2	5	7	10	13	16	19	21	24	26
90-100th Percentile	2	4	6	8	11	14	16	19	22	24
High Cost	2	5	8	11	14	17	20	23	25	27
Total	**24**	**44**	**67**	**90**	**115**	**140**	**163**	**186**	**208**	**228**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
0-10th Percentile	19	21	23	25	27	29	30	31	32	33
10-20th Percentile	19	20	22	25	27	28	30	31	32	33
20-30th Percentile	23	25	26	28	29	31	32	32	33	34
30-40th Percentile	20	22	24	25	27	28	30	31	32	33
40-50th Percentile	17	19	21	23	25	27	28	30	32	34
50-60th Percentile	15	17	19	20	22	24	26	29	31	33
60-70th Percentile	22	24	25	26	28	29	30	31	32	33
70-80th Percentile	28	29	30	31	32	32	33	33	33	34
80-90th Percentile	28	29	30	31	31	32	32	33	33	34
90-100th Percentile	26	28	29	30	30	31	32	32	33	33
High Cost	29	31	33	34	35	37	38	39	40	41
Total	**247**	**265**	**282**	**298**	**314**	**327**	**340**	**352**	**364**	**375**

Bundle Costs

Savings-Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	-$115	-$111	-$106	-$102	-$99	-$97	-$108	-$108	-$105	-$104
10-20th Percentile	-$5	-$8	-$7	-$5	-$5	-$5	-$15	-$15	-$15	-$15
20-30th Percentile	$14	$14	$14	$14	$14	$15	$14	$14	$15	$15
30-40th Percentile	$38	$38	$38	$38	$38	$38	$32	$32	$32	$32
40-50th Percentile	$42	$42	$42	$42	$41	$42	$40	$40	$39	$39
50-60th Percentile	$56	$56	$55	$55	$55	$55	$56	$55	$55	$54
60-70th Percentile	$68	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$138	$138	$139	$139	$139	$139	$136	$133	$130	$127
80-90th Percentile	$133	$135	$136	$137	$138	$137	$135	$134	$133	$132
90-100th Percentile	$192	$190	$189	$188	$188	$188	$187	$187	$187	$188
High Cost	$2,145	$2,144	$2,121	$2,094	$2,063	$2,001	$1,936	$1,876	$1,866	$1,906
Total	**$277**	**$312**	**$322**	**$330**	**$331**	**$325**	**$299**	**$285**	**$278**	**$271**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20-Year Average
0-10th Percentile	-$103	-$105	-$104	-$103	-$103	-$91	-$92	-$89	-$83	-$90	-$102
10-20th Percentile	-$15	-$27	-$27	-$27	-$27	-$28	-$29	-$29	-$30	-$30	-$18
20-30th Percentile	$15	$15	$15	$15	$15	$15	$15	$13	$13	$12	$14
30-40th Percentile	$32	$27	$27	$27	$26	$26	$26	$27	$27	$27	$32
40-50th Percentile	$38	$35	$35	$34	$34	$34	$34	$34	$34	$34	$38
50-60th Percentile	$52	$45	$44	$43	$42	$42	$42	$40	$40	$40	$48
60-70th Percentile	$70	$69	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$123	$120	$116	$112	$109	$107	$76	$73	$71	$69	$131
80-90th Percentile	$131	$130	$128	$126	$124	$121	$110	$111	$111	$112	$133
90-100th Percentile	$189	$190	$192	$194	$195	$196	$195	$195	$195	$195	$189
High Cost	$2,025	$2,204	$2,424	$2,653	$2,858	$3,049	$3,260	$3,261	$3,366	$3,463	$2,235
Total	**$267**	**$257**	**$257**	**$257**	**$259**	**$292**	**$296**	**$329**	**$359**	**$384**	$290

Supply-Side Resource Data

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.10%
Preferred	0.00%
Common	49.90%
Total	**100.00%**
Cost	
Debt	5.73%
Preferred	0.00%
Common	10.00%
Average Weighted Cost	7.86%

Financial Assumptions and Factors	
Plant operating (book) life	Expected Life of the Asset
Discount rate (weighted average cost of capital[1])	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 rate (% of investment)	0.49%
B2H annual property tax rate (% of investment)	0.55%
Property tax escalation rate	3.00%
B2H property tax escalation rate	1.67%
Annual insurance premiums (% of investment)	0.03%
B2H annual insurance premiums (% of investment)	0.03%
Insurance escalation rate	2.00%
B2H insurance escalation rate	2.00%
AFUDC rate (annual)	7.65%

[1] Incorporates tax effects.

Fuel Forecast Base Case (Nominal, $ per MMBTU)

Year	Generic Coal	Nuclear
2019	$2.40	
2020	$2.49	
2021	$2.55	
2022	$2.62	
2023	$2.68	$0.62
2024	$2.74	$0.63
2025	$2.80	$0.65
2026	$2.86	$0.66
2027	$2.91	$0.68
2028	$2.96	$0.69
2029	$3.01	$0.71
2030	$3.08	$0.72
2031	$3.15	$0.74
2032	$3.21	$0.75
2033	$3.30	$0.77
2034	$3.39	$0.79
2035	$3.46	$0.81
2036	$3.57	$0.82
2037	$3.65	$0.84
2038	$3.75	$0.86

Cost Inputs and Operating Assumptions (Costs in 2019$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital ($/kW)	Total Capital ($/kW)	Total Investment ($/kW)[2]	Fixed O&M ($/kW-mth)[3]	Variable O&M ($/MWh)	Integration ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (years)
Biomass (35 MW)	35	$3,577	$133	$3,710	$4,614	$3.13	$16.68	$0.00	0	30
Boardman to Hemingway (350 MW)	350	$0	$894	$894	$894	$0.42	$0.00	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,096	$102	$1,198	$1,401	$0.92	$2.90	$0.00	6,420	30
Geothermal (30 MW)	30	$6,014	$150	$6,164	$7,904	$15.05	$0.00	$0.00	0	25
Reciprocating Gas Engine (111.1 MW)	111	$885	$117	$1,002	$1,067	$1.00	$5.42	$0.00	8,300	40
Reciprocating Gas Engine (55.5 MW)	56	$994	$117	$1,111	$1,183	$1.00	$5.42	$0.00	8,300	40
SCCT—Frame F Class (170 MW)	170	$932	$122	$1,054	$1,122	$1.07	$7.48	$0.00	9,720	35
Small Modular Nuclear (60 MW)	60	$4,292	$165	$4,457	$6,722	$0.70	$2.09	$0.00	11,493	40
Solar PV—Residential Rooftop (.005 MW)	0.005	$3,590	$0	$3,590	$3,730	$1.79	$0.00	$0.00	0	25
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	40	$1,402	$150	$1,552	$1,613	$1.02	$0.00	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (10 MW)	50	$1,658	$150	$1,808	$1,879	$0.97	$0.49	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (20 MW)	60	$1,829	$150	$1,979	$2,056	$0.94	$0.81	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (30 MW)	70	$1,950	$150	$2,100	$2,183	$0.92	$1.03	$0.63	0	30
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	0.5	$1,823	-$62	$1,761	$1,830	$0.93	$0.00	$0.00	0	25
Storage—4-Hr Li Battery (5 MW)	5	$1,973	$52	$2,025	$2,064	$0.78	$2.47	$0.00	0	20
Storage—8-Hr Li Battery (5 MW)	5	$3,277	$52	$3,329	$3,393	$0.78	$2.47	$0.00	0	10
Storage—Pumped-Hydro (500 MW)	500	$1,800	$191	$1,991	$2,315	$0.33	$0.00	$0.00	0	75
Wind ID (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25
Wind WY (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Levelized Cost of Energy (Costs in 2023$, $/MWh)[1]

At stated capacity factors

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[2]	Fuel	Wholesale Energy	Net of Tax Credit/ Integration	Total Cost per MWh	Capacity Factor
Biomass (35 MW)[3]	$65	$36	$0	$0	$0	$101	85%
Boardman to Hemingway (350 MW)	$26	$3	$0	$40	-$8	$62	33%
CCCT (1x1) F Class (300 MW)	$28	$9	$34	$0	$0	$71	60%
Geothermal (30 MW)	$103	$41	$0	$0	$0	$144	88%
Reciprocating Gas Engine (111.1 MW)	$79	$29	$46	$0	$0	$155	15%
Reciprocating Gas Engine (55.5 MW)	$88	$30	$46	$0	$0	$164	15%
SCCT—Frame F Class (170 MW)	$256	$76	$53	$0	$0	$386	5%
Small Modular Nuclear (60 MW)	$83	$28	$10	$0	$0	$121	90%
Solar PV—Residential Rooftop (.005 MW)	$154	$25	$0	$0	$0	$180	21%
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$60	$12	$0	$0	-$5	$67	26%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$82	$16	$0	$0	-$7	$90	22%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$109	$20	$0	$0	-$10	$120	18%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$139	$25	$0	$0	-$13	$152	15%
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$71	$12	$0	$0	-$6	$77	26%
Storage—4-Hr Li Battery (5 MW)[3]	$201	$30	$0	$0	$0	$232	11%
Storage—8-Hr Li Battery (5 MW)[3]	$231	$19	$0	$0	$0	$250	23%
Storage—Pumped-Hydro (500 MW)[3]	$153	$21	$0	$0	$0	$175	16%
Wind ID (100 MW)	$60	$28	$0	$0	$26	$114	35%
Wind WY (100 MW)	$47	$22	$0	$0	$26	$94	45%

[1] Levelized costing in 2023$ assuming 2023 online date. Common online date five years into IRP planning window allows levelized costing to capture projected trends in resource costs.
[2] Non-Fuel O&M includes fixed and variable costs, property taxes.
[3] Fuel costs not included for biomass resource. Storage resources do not include costs of recharge energy. As noted in IRP, levelized costing for storage resources driven overwhelmingly by fixed costs.

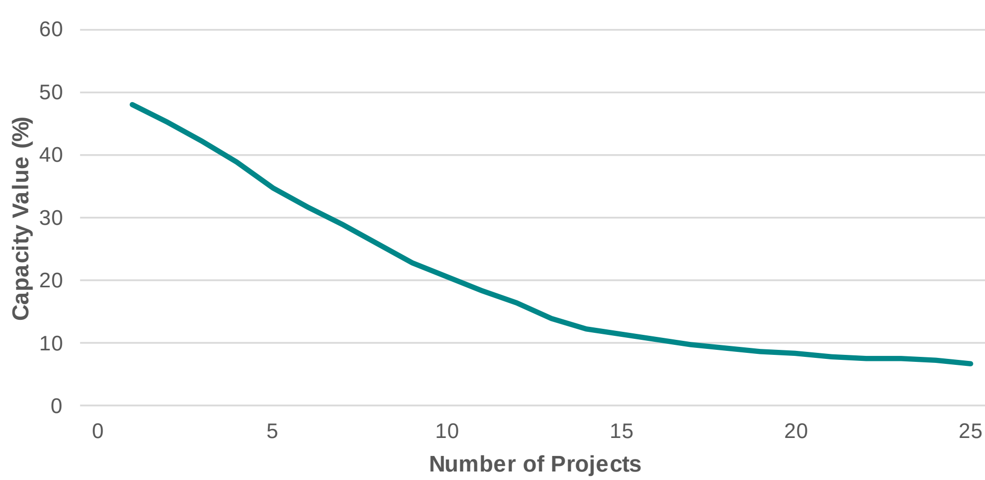
Levelized Capacity (fixed) Cost per kW/Month (Costs in 2019$)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Tax Credit	Total Cost per kW
Biomass (35 MW)	$37	$7	$0	$44
Boardman to Hemingway (350 MW)	$6	$1	-$2	$5
CCCT (1x1) F Class (300 MW)	$11	$2	$0	$13
Geothermal (30 MW)	$61	$24	$0	$85
Reciprocating Gas Engine (111.1 MW)	$8	$2	$0	$10
Reciprocating Gas Engine (55.5 MW)	$9	$2	$0	$11
SCCT—Frame F Class (170 MW)	$9	$2	$0	$11
Small Modular Nuclear (60 MW)	$50	$6	$0	$56
Solar PV—Residential Rooftop (.005 MW)	$29	$4	$0	$33
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$12	$2	-$1	$13
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$14	$3	-$1	$15
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$15	$3	-$1	$16
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$16	$3	-$1	$17
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$14	$2	-$1	$15
Storage—4-Hr Li Battery (5 MW)	$17	$2	$0	$20
Storage—8-Hr Li Battery (5 MW)	$43	$3	$0	$46
Storage—Pumped-Hydro (500 MW)	$16	$2	$0	$19
Wind ID (100 MW)	$15	$7	$0	$22
Wind WY (100 MW)	$13	$7	$0	$20

Solar Peak-Hour Capacity Credit (contribution to peak)

	Project MWAC	Total Installed MWAC ABV Current	Project Capacity Value (% Proj MWAC)	Project Capacity Value (MWAC)
Project 1	40	40	45.4%	18.1
Project 2	40	80	42.1%	16.9
Project 3	40	120	38.8%	15.5
Project 4	40	160	34.7%	13.9
Project 5	40	200	31.6%	12.7
Project 6	40	240	28.8%	11.5
Project 7	40	280	25.9%	10.4
Project 8	40	320	22.8%	9.1
Project 9	40	360	20.5%	8.2
Project 10	40	400	18.3%	7.3
Project 11	40	440	16.4%	6.5
Project 12	40	480	14.0%	5.6
Project 13	40	520	12.4%	5.0
Project 14	40	560	11.6%	4.6
Project 15	40	600	10.6%	4.2
Project 16	40	640	9.9%	4.0
Project 17	40	680	9.4%	3.7
Project 18	40	720	8.7%	3.5
Project 19	40	760	8.5%	3.4
Project 20	40	800	8.0%	3.2
Project 21	40	840	7.7%	3.1
Project 22	40	880	7.7%	3.1
Project 23	40	920	7.2%	2.9
Project 24	40	960	6.9%	2.8

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



PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio:

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2019	Valmy Unit 1	(127)	(127)[1]
2020	Boardman	(58)	(58)[2]
2022	Bridger Unit	(177)	(177)
2022	Solar	120	41
2022	Valmy Unit 2[3]	(133)	(133)[1]
2026	B2H	500 (Apr–Sep)/ 200 (Oct–Mar)	500
2026	Bridger Unit	(180)	(180)
2028	Bridger Unit	(174)	(174)
2030	Bridger Unit	(177)	(177)
2030	Solar	40	14
2030	Battery Storage	30	30
2030	Demand Response	5	5
2031	CCCT	300	300
2032	Demand Response	5	5
2033	Demand Response	5	5
2034	Solar	40	13
2034	Battery Storage	20	10
2034	Demand Response	5	5
2035	Solar	80	22
2035	Battery Storage	20	20
2035	Demand Response	5	5
2036	Solar	120	31
2036	Battery Storage	10	20
2036	Demand Response	5	5
2037	Reciprocating Engines	55.5	55.5
2037	Demand Response	5	5
2038	Reciprocating Engines	55.5	55.5
2038	Demand Response	5	5

1. Exit from North Valmy units not considered to affect capacity deficiency period because of IRP's assumed peak-hour wholesale electric market imports across existing north Valmy transmission line.
2. Ceased coal-fired operations at Boardman in 2020 considered a committed resource action.
3. 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 in chapter 1 of the *Second Amended 2019 IRP.*

2. Deficiency period start

   First capacity deficit = (42) MW July 2029

3. Intermittent generation integration costs

   Idaho—Schedule 87[2]

   Oregon—Schedule 85[3]

Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2019	4.84
2020	5.04
2021	5.31
2022	5.33
2023	5.44
2024	5.73
2025	5.75
2026	5.85
2027	5.89
2028	6.16
2029	6.21
2030	6.48
2031	6.53
2032	6.94
2033	7.07
2034	7.17
2035	7.55
2036	7.66
2037	8.04
2038	8.04

[2] idahopower.com/about-us/company-information/rates-and-regulatory/retail-tariffs-idaho/

[3] idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/

EXISTING RESOURCE DATA

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects Status as of December 31, 2019.

Project	MW	Contract On-line Date	Contract End Date
Hydro Projects			
Arena Drop	0.45	Sep-2010	Sep-2030
Baker City Hydro	0.24	Sep-2015	Sep-2030
Barber Dam	3.70	Apr-1989	Apr-2024
Birch Creek	0.05	Nov-1984	Nov-2039
Black Canyon #3	0.13	Apr-2019	Apr-2039
Black Canyon Bliss Hydro	0.03	Nov-2014	Oct-2035
Blind Canyon	1.63	Dec-2014	Dec-2034
Box Canyon	0.30	Feb-2019	Feb-2039
Briggs Creek	0.60	Oct-1985	Oct-2020
Bypass	9.96	Jun-1988	Jun-2023
Canyon Springs	0.11	Jan-2019	Jan-2039
Cedar Draw	1.55	Jun-1984	Jun-2039
Clear Springs Trout	0.56	Nov-2018	Nov-2038
Crystal Springs	2.44	Apr-1986	Apr-2021
Curry Cattle Company	0.25	Jun-2018	Jun-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034
Elk Creek	2.00	May-1986	May-2021
Fall River	9.10	Aug-1993	Aug-2028
Fargo Drop Hydroelectric	1.27	Apr-2013	Apr-2033
Faulkner Ranch	0.87	Aug-1987	Aug-2022
Fisheries Dev.	0.26	Jul-1990	As Delivered
Geo-Bon #2	0.93	Nov-1986	Nov-2021
Hailey CSPP	0.06	Jun-1985	Jun-2020
Hazelton A	8.10	Mar-2011	Mar-2026
Hazelton B	7.60	May-1993	May-2028
Head of U Canal Project	1.28	May-2015	Jun-2035
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030
Jim Knight	0.34	Jun-1985	Jun-2020
Koyle Small Hydro	1.25	Apr-2019	Apr-2039
Lateral # 10	2.06	May-1985	May-2020
Lemoyne	0.08	Jun-1985	Jun-2020
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035
Little Wood River Res	2.85	Feb-1985	Feb-2020
Littlewood/Arkoosh	0.87	Aug-1986	Aug-2021
Low Line Canal	7.97	May-1985	May-2020
Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Lowline #2	2.79	Apr-1988	Apr-2023
Magic Reservoir	9.07	Jun-1989	Jun-2024
Malad River	1.17	May-2019	May-2039
Marco Ranches	1.20	Aug-1985	Aug-2020
MC6 Hydro	2.10	Jul-2019	Jul-2039
Mile 28	1.50	Jun-1994	Jun-2029
Mitchell Butte	2.09	May-1989	Dec-2033
Mora Drop Small Hydro	1.85	Sep-2006	Sep-2026
Mud Creek/S&S	0.52	Feb-2017	Feb-2037
Mud Creek/White	0.21	Jan-1986	Jan-2021
North Gooding Main	1.30	Oct-2016	Oct-2036
Owyhee Dam CSPP	5.00	Aug-1985	May-2033
Pigeon Cove	1.89	Oct-1984	Nov-2039
Pristine Springs #1	0.10	May-2015	May-2020
Pristine Springs #3	0.20	May-2015	May-2020
Reynolds Irrigation	0.26	May-1986	May-2021
Rock Creek #1	2.17	Jan-2018	Jan-2038
Rock Creek #2	1.90	Apr-1989	Apr-2024
Sagebrush	0.43	Sep-1985	Sep-2020
Sahko Hydro	0.50	Feb-2011	Feb-2021
Schaffner	0.53	Aug-1986	Aug-2021
Shingle Creek	0.22	Aug-2017	Aug-2022
Shoshone #2	0.58	May-1996	May-2031
Shoshone CSPP	0.36	Feb-2017	Feb-2037
Snake River Pottery	0.07	Nov-1984	Dec-2027
Snedigar	0.54	Jan-1985	Jan-2040
Tiber Dam	7.50	Jun-2004	Jun-2024
Trout-Co	0.24	Dec-1986	Dec-2021
Tunnel #1	7.00	Jun-1993	Feb-2035
White Water Ranch	0.16	Aug-1985	Aug-2020
Wilson Lake Hydro	8.40	May-1993	May-2028

Total Hydro Nameplate Rating 148.85 MW

Thermal Projects			
Simplot Pocatello Cogen	15.90	Mar-2019	Mar-2022
TASCO—Nampa Natural Gas	2	Sep-2003	As Delivered
TASCO—Twin Falls Natural Gas	3	Aug-2001	As Delivered
Total Thermal Nameplate Rating 20.90 MW			

Project	MW	Contract On-line Date	End Date	Project	MW	Contract On-line Date	End Date
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2010	Aug-2020	Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027
Bannock County Landfill	3.20	May-2014	May-2034	Pocatello Waste	0.46	Dec-1985	Dec-2020
Bettencourt Dry Creek	2.25	May-2010	May-2020	Rock Creek Dairy	4.00	Aug-2012	Aug-2027
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	SISW LFGE	5.00	Oct-2018	Estimated
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	6.25	Jun-2018	Jun-2038
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029				
Total Biomass Nameplate Rating 35.70 MW							

Solar Projects							
American Falls Solar II, LLC	20.00	Mar-2017	Mar-2037	Murphy Flat Power, LLC	20.00	Mar-2017	Mar-2037
American Falls Solar, LLC	20.00	Mar-2017	Mar-2037	Ontario Solar Center	3.00	Dec-2019	Estimated
Baker Solar Center	15.00	Dec-2019	Estimated	Open Range Solar Center, LLC	10.00	Mar-2017	Mar-2037
Brush Solar	2.75	Oct-2019	Estimated	Orchard Ranch Solar, LLC	20.00	Oct-2016	Oct-2036
Grand View PV Solar Two	80.00	Dec-2016	Dec-2036	Railroad Solar Center, LLC	4.50	Dec-2016	Dec-2036
Grove Solar Center, LLC	6.00	Oct-2016	Oct-2036	Simcoe Solar, LLC	20.00	Mar-2017	Mar-2037
Hyline Solar Center, LLC	9.00	Nov-2016	Nov-2036	Thunderegg Solar Center, LLC	10.00	Nov-2016	Nov-2036
ID Solar 1	40.00	Aug-2016	Jan-2036	Vale Air Solar Center, LLC	10.00	Nov-2016	Nov-2036
Morgan Solar	3.00	Oct-2019	Estimated	Vale 1 Solar	3.00	Oct-2019	Estimated
Mt. Home Solar 1, LLC	20.00	Mar-2017	Mar-2037				
Total Solar Nameplate Rating 316.25 MW							

Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Mainline Windfarm	23.00	Dec-2012	Dec-2032
Benson Creek Windfarm	10.00	Mar-2017	Mar-2037	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031	Oregon Trail Wind Park	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm LLC	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Prospector Windfarm	10.00	Mar-2017	Mar-2037
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Durbin Creek Windfarm	10.00	Mar-2017	Mar-2037	Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Golden Valley Wind Park	12.00	Feb-2011	Feb-2031	Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032	Thousand Springs Wind Park	12.00	Jan-2011	Jan-2031
High Mesa Wind Project	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	May-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Jett Creek Windfarm	10.00	Mar-2017	Mar-2037	Willow Spring Windfarm	10.00	Mar-2017	Mar-2037
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW							
Total Nameplate Rating 1,148.62 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements

Project	MW	Contract On-Line Date	End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total Wind Nameplate Rating	**101**		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	November 2012	November 2037
Total Geothermal Nameplate Rating	**35**		
Solar projects			
Jackpot Solar Facility	120	December 2022	Estimated
Total Solar Nameplate Rating	**120**		
Total Nameplate Rating	**256**		

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Flow Modeling

Models

Idaho Power uses two primary models to develop future flow scenarios for the IRP. The Snake River Planning Model (SRPM) is used to model surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to model aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

Model Inputs

The inputs for the 2019 IRP were derived, in part, from management practices outlined in an agreement between the Surface Water Coalition (SWC) and Idaho Groundwater Appropriators (IGWA). The agreement set out specific targets for several management practices that include aquifer recharge, system conversions, and a total reduction in ground water diversions of 240,000 acre-feet. Model inputs also included a long-term analysis of trends in reach gains to the Snake River from Palisades Dam to King Hill. Weather modification activities conducted by Idaho Power and other participating entities were included in the modeling effort.

Recharge capacity modeled for the 2019 IRP included diversions with the capability of diverting all available water at the Snake River below Milner Dam during the winter months under typical release conditions. These diversions can have a significant impact to flows downstream of Milner Dam. Modeled recharge diversions peak at approximately 339,000 acre-ft in IRP year 2025. In IRP year 2025, approximately 145,000 acre-ft of recharge diversions occur above American Falls Reservoir and 195,000 acre-ft is diverted at Milner Dam. Modeled recharge diversions decline only slightly from the peak in 2025 through the end of the modeling period in 2038. The 2019 IRP included approximately 85,000 acre-ft of additional annual recharge not included in the 2017 IRP. This increase in projected recharge activity is based upon recharge activity observed from spring 2016 through spring 2018. The additional annual recharge volume can be attributed to the development of private aquifer recharge and state sponsored recharge demonstrating a higher level of recharge capacity than anticipated in the 2017 IRP.

System conversion projects involve the conversion of ground water supplied irrigated land to surface water-supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources and local ground water districts. The current model assumes a total of 48,000 acres of converted land on the ESPA. This is an increase of approximately 30,000 acres over the 2017 IRP and is based on data collected from a local groundwater district. Water savings for conversion projects are calculated at a rate of 2.0 acre-ft per converted acre. Diversions for conversion projects peak at approximately 95,000 acre-ft in model year 2024 and are held essentially constant through the end of the modeling period in year 2038.

The model accounted for a 190,000 acre-ft decrease in ground water pumping from the ESPA. The decrease was spread evenly over ground water irrigated lands that are subject to the agreement between the SWC and the IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft per year but the agreement allows for a portion of that to be offset by aquifer recharge activities. Based on recent management activity, approximately 50,000 acre-ft per year reduction is accomplished through other forms of mitigation such as private aquifer recharge.

The 2019 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Lower Salmon Falls Dam to Bliss demonstrated a statistically significant decline for the period of 1988 to 2017. The long-term declines are still present, but they have improved since the 2017 IRP. Reach gains to the Snake River increased in 2016 and 2017. The increases in reach gains may be due to a combination of factors including recent high runoff events, good supply of irrigation water, and aquifer recharge activities. The declines calculated for the 2019 IRP are approximately 25 to 30 percent less than those used in the 2017 IRP. This results in additional water in the Snake River throughout the planning period.

Weather modification was added to the model at various levels of development. For IRP years 2019 through 2024, weather modification was increased to reflect projected levels of program development in Eastern Idaho, the Wood River and Boise basins. Beyond IRP year 2024, weather-modification levels in these three basins were held constant through the remainder of the IRP planning period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP planning period.

The modeling also accounts for changes in reach gains from observed water management activities on the ESPA since 2014. Reach gain calculations include management activities that have occurred since 2014. Data from IDWR and other sources were used to determine the magnitude of the management activities and the ESPAM was used to model the projected reach gains. The impact of those management activities can have impacts on reach gains for up to 30 years.

Model Results

The combined model allows for the inclusion of all future management activities, and the resulting reach gains from those management activities into Idaho Power's 2019 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex (HCC), but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and a decrease in ground water pumping, directly impact the annual volume of water expected through the HCC as well as the timing and location of gains within the system.

Overall inflow to Brownlee Reservoir increases from IRP modeled year 2019 through 2024. Flows peak in 2025 with the 50 percent exceedance annual inflow to Brownlee Reservoir at just over 12.33 million acre-ft/year. In 2038, those flows declined to approximately 12.03 million acre-ft per year. For the April through July volume the peak occurs in modeled year 2024 with a volume of 5.58 million acre-ft. In the final modeled year of 2038, the April through July inflow to Brownlee decreases to 5.47 million acre-ft.

The Brownlee inflow volumes for the 2019 IRP are higher than those reported in the 2017 IRP. There are several factors leading to the increase in modeled flows. The change in reach declines had a significant impact on inflows to Brownlee Reservoir. For example, in model year 2036, the increase in Brownlee inflow volume attributable to changes in reach declines between the 2019 and 2017 IRPs is approximately 337,000 acre-feet, Weather modification volume increased by approximately 200,000 acre-ft per year in the 2019 IRP as compared to the 2017 IRP. The other notable change is the observed recharge conducted in 2016 and 2017 exceeded recharge volume assumptions made during the 2017 IRP.

Over 1,000,000 acre-ft water were recharged to the ESPA during 2016 and 2017. While outside the modeling period of 2019 to 2038, the reach gains resulting from this recharge are modeled and significantly increase reach gains for the modeling period. The modeled reach gains from this recharge increased reach gains in the Snake River and inflows to Brownlee Reservoir particularly during the first five years of the modeling period.

2019 Model Parameters (acre-feet/year)

Year	Managed Recharge: Above American Falls	Managed Recharge: Below American Falls	Managed Recharge: Total	Weather Modification	System Conversions	Ground Water Pumping Declines	Reach Declines: American Falls Inflows	Reach Declines: Below Milner Inflows
2019	145,210	192,991	338,201	978,140	96,138	190,053	167,239	135,702
2020	144,682	193,002	337,685	1,164,927	95,105	190,053	182,442	148,039
2021	144,559	193,002	337,562	1,232,907	95,105	190,053	197,646	160,375
2022	144,436	193,052	337,489	1,241,693	96,140	190,053	212,849	172,712
2023	144,680	193,298	337,978	1,252,091	95,105	190,053	228,053	185,049
2024	144,381	193,187	337,568	1,268,605	95,537	190,053	243,256	197,385
2025	144,319	194,802	339,121	1,268,605	94,928	190,053	258,460	209,722
2026	144,319	193,195	337,514	1,268,605	94,928	190,053	273,663	222,058
2027	144,319	193,139	337,459	1,268,605	94,928	190,053	288,867	234,395
2028	144,319	193,024	337,344	1,268,605	94,928	190,053	304,071	246,732
2029	144,319	192,913	337,233	1,268,605	94,928	190,053	319,274	259,068
2030	144,490	192,669	337,159	1,268,605	95,414	190,053	334,478	271,405
2031	143,631	192,550	336,181	1,268,605	95,351	190,053	349,681	283,741
2032	143,508	192,429	335,937	1,268,605	95,351	190,053	364,885	296,078
2033	143,693	192,364	336,056	1,268,605	95,412	190,053	380,088	308,414
2034	143,262	192,001	335,263	1,268,605	95,535	190,053	395,292	320,751
2035	143,865	192,058	335,924	1,268,605	95,535	190,053	410,495	333,088
2036	143,324	191,878	335,202	1,268,605	95,535	190,053	425,699	345,424
2037	143,139	191,691	334,831	1,268,605	95,291	190,053	440,902	357,761
2038	142,467	191,634	334,101	1,268,605	95,172	190,053	456,106	370,097

Hydro Modeling Results (aMW)

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2019	Jan	750	350	1,100	596	204	800	434	177	612
	Feb	787	355	1,141	682	310	993	682	310	993
	Mar	815	276	1,092	588	225	813	588	225	813
	Apr	1,058	406	1,465	750	274	1,024	750	274	1,024
	May	913	432	1,344	875	320	1,195	875	320	1,195
	June	992	385	1,377	678	333	1,011	678	333	1,011
	July	551	292	842	520	282	802	520	282	802
	Aug	466	251	716	437	242	679	437	242	679
	Sept	568	241	809	464	231	696	464	231	696
	Oct	417	215	632	395	206	601	395	206	601
	Nov	343	195	538	347	180	527	347	180	527
	Dec	579	362	941	484	189	673	484	189	673
Annual aMW		**686**	**313**	**1,000**	**568**	**250**	**818**	**555**	**248**	**802**
2020	Jan	758	355	1,113	612	257	869	444	181	625
	Feb	803	365	1,168	689	321	1,010	689	321	1,010
	Mar	820	282	1,103	595	234	828	595	234	828
	Apr	1,072	426	1,498	761	290	1,051	761	290	1,051
	May	931	454	1,385	877	332	1,209	877	332	1,209
	June	1,010	431	1,441	704	335	1,039	704	335	1,039
	July	551	292	843	520	283	803	520	283	803
	Aug	467	251	717	437	243	680	437	243	680
	Sept	581	241	822	468	234	702	468	234	702
	Oct	414	216	629	391	206	597	391	206	597
	Nov	338	197	536	348	181	528	348	181	528
	Dec	584	374	958	486	190	675	486	190	675
Annual aMW		**694**	**324**	**1,018**	**574**	**259**	**833**	**560**	**252**	**812**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2021	Jan	760	355	1,115	613	257	870	446	182	628
	Feb	803	365	1,168	690	320	1,010	690	320	1,010
	Mar	824	283	1,107	602	235	837	602	235	837
	Apr	1,084	428	1,512	769	292	1,061	769	292	1,061
	May	946	455	1,401	882	334	1,216	882	334	1,216
	June	1,024	432	1,456	708	336	1,044	708	336	1,044
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	682	438	244	682
	Sept	584	241	826	470	234	704	470	234	704
	Oct	415	216	631	390	207	597	390	207	597
	Nov	337	198	535	348	181	529	348	181	529
	Dec	585	376	961	487	190	677	487	190	677
Annual aMW		**698**	**324**	**1,023**	**576**	**259**	**836**	**562**	**253**	**816**
2022	Jan	760	355	1,115	613	260	873	446	182	628
	Feb	803	366	1,168	690	320	1,010	690	320	1,010
	Mar	824	284	1,107	602	235	837	602	235	837
	Apr	1,085	428	1,513	770	295	1,065	770	295	1,065
	May	946	458	1,404	882	336	1,217	882	336	1,217
	June	1,025	435	1,461	710	336	1,046	710	336	1,046
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	681	438	244	681
	Sept	585	241	826	470	234	704	470	234	704
	Oct	415	216	630	390	207	597	390	207	597
	Nov	337	198	535	347	181	528	347	181	528
	Dec	586	378	964	487	190	677	487	190	677
Annual aMW		**698**	**325**	**1,024**	**576**	**260**	**837**	**563**	**254**	**816**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2023	Jan	759	356	1,115	613	265	877	445	182	628
	Feb	802	366	1,168	689	320	1,009	689	320	1,009
	Mar	824	285	1,109	601	236	837	601	236	837
	Apr	1,084	428	1,513	769	298	1,068	769	298	1,068
	May	945	461	1,406	882	339	1,221	882	339	1,221
	June	1,032	441	1,472	711	338	1,049	711	338	1,049
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	437	244	681	437	244	681
	Sept	586	241	827	469	234	703	469	234	703
	Oct	415	216	631	390	207	597	390	207	597
	Nov	335	198	533	347	181	529	347	181	529
	Dec	586	380	966	487	190	678	487	190	678
Annual aMW		**699**	**326**	**1,025**	**576**	**261**	**838**	**562**	**254**	**817**
2024	Jan	759	357	1,116	613	271	884	445	182	627
	Feb	802	366	1,168	688	320	1,007	688	320	1,007
	Mar	824	286	1,110	601	236	837	601	236	837
	Apr	1,085	429	1,513	770	300	1,070	770	300	1,070
	May	947	463	1,409	882	341	1,223	882	341	1,223
	June	1,033	444	1,477	712	338	1,050	712	338	1,050
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	717	437	244	681	437	244	681
	Sept	586	241	828	468	234	703	468	234	703
	Oct	415	215	630	390	207	596	390	207	596
	Nov	335	198	533	348	181	529	348	181	529
	Dec	586	381	968	487	190	678	487	190	678
Annual aMW		**699**	**327**	**1,026**	**576**	**262**	**838**	**562**	**255**	**817**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2025	Jan	759	356	1,115	612	268	880	444	182	627
	Feb	800	366	1,165	688	319	1,007	688	319	1,007
	Mar	823	286	1,109	600	235	835	600	235	835
	Apr	1,084	428	1,512	768	300	1,068	768	300	1,068
	May	946	462	1,409	882	341	1,223	882	341	1,223
	June	1,032	443	1,475	711	337	1,049	711	337	1,049
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	716	436	244	680	436	244	680
	Sept	584	241	825	467	234	701	467	234	701
	Oct	414	215	630	389	206	596	389	206	596
	Nov	336	198	534	348	181	529	348	181	529
	Dec	586	380	966	486	190	677	486	190	677
Annual aMW		**698**	**327**	**1,025**	**576**	**262**	**837**	**562**	**255**	**816**
2026	Jan	758	355	1,113	611	265	877	444	182	626
	Feb	797	365	1,162	687	319	1,006	687	319	1,006
	Mar	822	286	1,108	599	234	833	599	234	833
	Apr	1,083	428	1,511	769	300	1,068	769	300	1,068
	May	946	462	1,408	882	341	1,222	882	341	1,222
	June	1,032	443	1,474	711	337	1,048	711	337	1,048
	July	549	292	841	519	284	802	519	284	802
	Aug	465	251	716	436	244	680	436	244	680
	Sept	582	241	823	466	234	700	466	234	700
	Oct	413	215	628	389	206	596	389	206	596
	Nov	337	198	534	348	181	529	348	181	529
	Dec	584	378	962	485	190	675	485	190	675
Annual aMW		**697**	**326**	**1,023**	**575**	**261**	**836**	**561**	**254**	**815**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2027	Jan	757	354	1,111	611	262	872	443	181	625
	Feb	792	364	1,156	685	318	1,003	685	318	1,003
	Mar	821	284	1,106	599	234	832	599	234	832
	Apr	1,082	427	1,509	767	299	1,066	767	299	1,066
	May	946	461	1,407	882	340	1,222	882	340	1,222
	June	1,031	441	1,472	710	337	1,047	710	337	1,047
	July	549	292	840	518	283	801	518	283	801
	Aug	465	251	715	435	243	679	435	243	679
	Sept	579	241	820	464	234	698	464	234	698
	Oct	412	215	627	390	206	596	390	206	596
	Nov	337	198	535	347	181	528	347	181	528
	Dec	583	376	959	485	190	675	485	190	675
Annual aMW		**696**	**325**	**1,021**	**574**	**261**	**835**	**560**	**254**	**814**
2028	Jan	756	353	1,109	610	258	868	443	181	623
	Feb	789	362	1,151	684	316	1,000	684	316	1,000
	Mar	820	283	1,102	598	232	830	598	232	830
	Apr	1,082	427	1,509	767	298	1,065	767	298	1,065
	May	945	460	1,404	882	339	1,221	882	339	1,221
	June	1,030	440	1,470	709	337	1,046	709	337	1,046
	July	548	291	840	517	283	800	517	283	800
	Aug	464	250	714	435	243	678	435	243	678
	Sept	576	241	817	463	234	697	463	234	697
	Oct	411	215	626	389	206	595	389	206	595
	Nov	338	198	536	347	181	528	347	181	528
	Dec	581	373	953	483	189	673	483	189	673
Annual aMW		**695**	**324**	**1,019**	**574**	**260**	**833**	**560**	**253**	**813**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2029	Jan	755	352	1,107	609	253	861	441	180	621
	Feb	786	360	1,146	683	314	997	683	314	997
	Mar	819	281	1,100	596	230	826	596	230	826
	Apr	1,081	426	1,507	767	298	1,065	767	298	1,065
	May	944	456	1,400	881	338	1,219	881	338	1,219
	June	1,029	439	1,468	708	336	1,044	708	336	1,044
	July	548	291	839	517	283	800	517	283	800
	Aug	463	250	713	434	243	677	434	243	677
	Sept	573	240	813	461	233	694	461	233	694
	Oct	410	215	625	389	206	595	389	206	595
	Nov	339	197	537	347	181	528	347	181	528
	Dec	579	370	949	482	189	671	482	189	671
Annual aMW		**694**	**323**	**1,017**	**573**	**259**	**831**	**559**	**253**	**812**
2030	Jan	753	351	1,104	606	247	853	441	178	619
	Feb	783	359	1,141	682	312	994	682	312	994
	Mar	817	280	1,097	596	227	823	596	227	823
	Apr	1,079	426	1,505	766	297	1,063	766	297	1,063
	May	944	455	1,399	881	331	1,212	881	331	1,212
	June	1,026	436	1,462	707	335	1,041	707	335	1,041
	July	547	291	838	516	283	799	516	283	799
	Aug	463	250	712	434	243	676	434	243	676
	Sept	569	240	809	459	233	692	459	233	692
	Oct	410	215	625	390	206	595	390	206	595
	Nov	341	197	538	347	181	527	347	181	527
	Dec	577	366	943	481	189	670	481	189	670
Annual aMW		**692**	**322**	**1,014**	**572**	**257**	**829**	**558**	**251**	**809**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2031	Jan	752	349	1,101	601	241	842	440	177	617
	Feb	781	359	1,140	680	308	988	680	308	988
	Mar	816	279	1,095	595	225	819	595	225	819
	Apr	1,078	425	1,503	765	297	1,062	765	297	1,062
	May	944	454	1,398	881	332	1,212	881	332	1,212
	June	1,022	434	1,455	706	335	1,040	706	335	1,040
	July	546	291	837	515	283	798	515	283	798
	Aug	462	250	712	433	242	675	433	242	675
	Sept	566	240	806	453	232	686	453	232	686
	Oct	411	214	626	390	205	596	390	205	596
	Nov	340	197	536	346	180	527	346	180	527
	Dec	575	363	937	480	189	668	480	189	668
Annual aMW		**691**	**321**	**1,012**	**570**	**256**	**826**	**557**	**250**	**807**
2032	Jan	750	348	1,098	600	236	835	440	177	617
	Feb	779	358	1,136	679	306	985	679	306	985
	Mar	815	278	1,093	593	224	817	593	224	817
	Apr	1,077	424	1,501	765	295	1,060	765	295	1,060
	May	943	453	1,396	880	332	1,212	880	332	1,212
	June	1,017	432	1,448	705	335	1,040	705	335	1,040
	July	546	291	836	515	282	797	515	282	797
	Aug	462	249	711	432	242	674	432	242	674
	Sept	562	240	802	452	232	684	452	232	684
	Oct	413	214	627	390	205	595	390	205	595
	Nov	340	196	536	346	180	526	346	180	526
	Dec	573	359	931	478	189	667	478	189	667
Annual aMW		**690**	**320**	**1,010**	**569**	**255**	**824**	**556**	**250**	**806**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2033	Jan	749	347	1,096	599	230	829	438	177	615
	Feb	777	357	1,133	677	305	982	677	305	982
	Mar	814	277	1,090	592	223	815	592	223	815
	Apr	1,076	424	1,499	763	293	1,056	763	293	1,056
	May	942	452	1,395	880	330	1,210	880	330	1,210
	June	1,012	430	1,443	704	334	1,038	704	334	1,038
	July	545	291	836	514	282	796	514	282	796
	Aug	461	249	710	432	242	674	432	242	674
	Sept	558	240	798	450	232	682	450	232	682
	Oct	414	214	628	390	205	595	390	205	595
	Nov	341	196	537	346	180	526	346	180	526
	Dec	572	355	927	475	188	664	475	188	664
Annual aMW		**688**	**319**	**1,008**	**568**	**254**	**822**	**555**	**249**	**804**
2034	Jan	748	346	1,093	598	225	823	437	177	613
	Feb	775	356	1,131	676	304	980	676	304	980
	Mar	813	274	1,087	590	222	812	590	222	812
	Apr	1,074	423	1,497	763	291	1,053	763	291	1,053
	May	941	451	1,393	879	329	1,209	879	329	1,209
	June	1,011	429	1,440	702	334	1,036	702	334	1,036
	July	544	290	835	514	282	795	514	282	795
	Aug	460	249	709	431	242	673	431	242	673
	Sept	554	239	794	448	231	679	448	231	679
	Oct	416	214	630	391	205	596	391	205	596
	Nov	341	196	537	345	180	525	345	180	525
	Dec	571	350	921	473	188	661	473	188	661
Annual aMW		**687**	**318**	**1,005**	**567**	**253**	**820**	**554**	**249**	**803**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2035	Jan	746	344	1,091	598	219	817	436	176	612
	Feb	768	354	1,121	674	303	977	674	303	977
	Mar	811	273	1,084	589	221	809	589	221	809
	Apr	1,072	422	1,494	762	289	1,051	762	289	1,051
	May	941	450	1,391	879	329	1,208	879	329	1,208
	June	1,011	429	1,439	701	333	1,034	701	333	1,034
	July	544	290	834	513	282	794	513	282	794
	Aug	460	249	708	430	241	672	430	241	672
	Sept	550	239	789	446	231	677	446	231	677
	Oct	419	213	632	390	205	595	390	205	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	571	346	917	471	188	659	471	188	659
Annual aMW		**686**	**317**	**1,003**	**566**	**252**	**818**	**553**	**248**	**801**
2036	Jan	745	344	1,089	594	217	811	434	176	610
	Feb	765	351	1,117	673	301	975	673	301	975
	Mar	810	272	1,082	588	220	807	588	220	807
	Apr	1,072	421	1,493	761	288	1,048	761	288	1,048
	May	940	450	1,390	879	326	1,205	879	326	1,205
	June	1,009	427	1,437	699	333	1,032	699	333	1,032
	July	543	290	833	512	281	794	512	281	794
	Aug	459	248	707	430	241	671	430	241	671
	Sept	546	239	785	444	230	675	444	230	675
	Oct	420	213	633	390	204	595	390	204	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	570	341	911	471	188	658	471	188	658
Annual aMW		**685**	**316**	**1,001**	**565**	**251**	**816**	**552**	**247**	**800**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2037	Jan	743	343	1,086	592	215	806	433	175	608
	Feb	765	350	1,115	672	299	971	672	299	971
	Mar	809	270	1,079	585	217	802	585	217	802
	Apr	1,069	420	1,489	760	287	1,047	760	287	1,047
	May	940	449	1,388	879	326	1,204	879	326	1,204
	June	1,008	424	1,432	698	333	1,030	698	333	1,030
	July	542	290	832	511	281	793	511	281	793
	Aug	458	248	707	429	241	670	429	241	670
	Sept	544	239	783	442	230	672	442	230	672
	Oct	419	213	632	391	204	595	391	204	595
	Nov	340	194	534	346	179	525	346	179	525
	Dec	568	336	905	469	187	656	469	187	656
Annual aMW		**684**	**315**	**999**	**564**	**250**	**814**	**551**	**247**	**798**
2038	Jan	738	342	1,079	591	203	794	432	175	607
	Feb	762	351	1,113	670	295	964	670	295	964
	Mar	808	269	1,077	584	211	795	584	211	795
	Apr	1,067	419	1,487	759	286	1,045	759	286	1,045
	May	940	447	1,387	879	325	1,203	879	325	1,203
	June	1,023	423	1,445	696	332	1,029	696	332	1,029
	July	542	289	831	511	281	792	511	281	792
	Aug	458	248	706	428	241	669	428	241	669
	Sept	543	239	782	440	229	669	440	229	669
	Oct	418	213	631	391	204	594	391	204	594
	Nov	339	195	534	346	179	525	346	179	525
	Dec	568	331	899	468	187	655	468	187	655
Annual aMW		**684**	**314**	**997**	**564**	**248**	**811**	**550**	**245**	**796**

Long-Term Capacity Expansion Results (MW)

	Portfolio 1					Portfolio 13				
Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Price Forecast				
Carbon Assumption:	Zero Carbon Price Forecast					Zero Carbon Price Forecast				
B2H Assumption:	No B2H					B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022					(177)					(177)
2023		120		5			120			
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028			10	5						
2029		80	40	5						
2030		40	20	5					5	
2031		80	20	5					5	
2032	111			5					5	
2033									5	
2034	300				(531)				5	(531)
2035	411					411	80	50	5	
2036									5	
2037	56					300			5	
2038	56								5	
Nameplate Total (MW)	933	320	90	50	(1,026)	711	200	50	45	(1,026)
B2H	–					500				
Net Build	367					480				

	Portfolio 2					**Portfolio 14**				
Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast				
Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast				
B2H Assumption:	No B2H					B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022					(177)					(177)
2023		120		5			120			
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028		40	30	5						
2029		40	20	5						
2030	300			5					5	
2031				5					5	
2032				5					5	
2033	111								5	
2034					(531)				5	(531)
2035	411	120	30			300	160	70	5	
2036						300	40	10	5	
2037	56								5	
2038	56								5	
Nameplate Total (MW)	933	320	80	50	(1,026)	600	320	80	45	(1,026)
B2H	–					500				
Net Build	357					519				

	Portfolio 3						Portfolio 15					
Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast						Generational Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			480						400			
2022			120			(177)		100				(177)
2023					5							
2024		100			5							
2025		100	320		5	(133)						(133)
2026		100			5	(180)						(180)
2027			200	80	5			100				
2028					5			100			5	(174)
2029		100	40		5	(174)		100			5	
2030	300	100			5			100	440		5	(177)
2031			5		5				200	80	5	
2032					5						5	
2033	111						300				5	
2034						(177)					5	
2035	300										5	
2036											5	
2037											5	
2038	111						300					
Nameplate Total (MW)	822	500	1,165	80	50	(1,026)	600	500	1,040	80	50	(1,026)
B2H	-						500					
Net Build	1,591						1,744					

	Portfolio 4						Portfolio 16					
Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast					
Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			480									
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025		100	320		5	(133)						(133)
2026		100	40	30	5	(180)						(180)
2027		100	200	50	5			100	920	50	5	-
2028		100			5	(174)		100			5	(174)
2029	300	100			5			100				
2030		100			5		111	100			5	(177)
2031					5			100	120	30	5	
2032					5			100			5	
2033	111						300				5	
2034						(177)					5	
2035	300										5	
2036											5	
2037											5	
2038	111											
Nameplate Total (MW)	822	600	1,160	80	50	(1,026)	411	600	1,160	80	50	(1,026)
B2H							500					
Net Build	1,686						1,775					

	Portfolio 5							Portfolio 17				
Gas Assumption:	Mid Gas Price Forecast							Mid Gas Price Forecast				
Carbon Assumption:	Zero Carbon Price Forecast							Zero Carbon Price Forecast				
B2H Assumption:	No B2H							B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Geothermal**	**Nuclear**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019							(127)					(127)
2020							(58)					(58)
2021												
2022		120										
2023						5						
2024						5						
2025						5	(133)					(133)
2026			5			5						
2027						5						
2028						5						
2029						5						
2030		5				5						
2031						5						
2032		40	30			5					5	
2033		40	20		60						5	
2034							(708)				5	(708)
2035	633	290	30					411	240	80	5	
2036					60						5	
2037					60			111			5	
2038		120		30							5	
Nameplate Total (MW)	633	615	85	30	180	50	(1,026)	522	240	80	35	(1,026)
B2H	–							500				
Net Build	567							351				

	Portfolio 6					**Portfolio 18**						
Gas Assumption:	Mid Gas Price Forecast					Mid Gas Price Forecast						
Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Geothermal**	**Biomass**	**Demand Response**	**Coal Exit**
2019					(127)							(127)
2020					(58)							(58)
2021												
2022		120										
2023				5								
2024				5								
2025				5	(133)							(133)
2026				5								
2027				5								
2028				5								
2029				5								
2030				5								
2031				5								
2032		40	30	5							5	
2033		80	30		(177)		40	30			5	
2034	300				(531)		45	10			5	(708)
2035	411	485	20			300	205	40			5	
2036							160	10			5	
2037	111					56			30	30	5	
2038		80									5	
Nameplate Total (MW)	822	805	80	50	(1,026)	356	450	90	30	30	35	(1,026)
B2H	–					500						
Net Build	731					465						

	Portfolio 7						Portfolio 19					
Gas Assumption:	Mid Gas Price Forecast						Mid Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast						Generational Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021		100	440					100	400			
2022		100	440			(177)		100				(177)
2023		100	160	20	5			100				
2024		100			5							
2025		100			5	(133)						(133)
2026		100			5	(180)						(180)
2027					5			100	560	40	5	
2028			120	60	5	(174)		100			5	(174)
2029	300				5			100	80	40	5	
2030					5	(177)			5		5	(177)
2031	300				5				5		5	
2032					5						5	
2033	111						300					
2034												
2035			5									
2036	111											
2037												
2038							111					
Nameplate Total (MW)	822	600	1,165	80	50	(1,026)	411	600	1,050	80	30	(1,026)
B2H	–						500					
Net Build	1,691						1,645					

	Portfolio 8						**Portfolio 20**				
Gas Assumption:	Mid Gas Price Forecast						Mid Gas Price Forecast				
Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
B2H Assumption:	No B2H						B2H in Service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Coal Exit**
2019						(127)					(127)
2020						(58)					(58)
2021			520								
2022		100	120			(177)					(177)
2023		100			5				120		
2024		100	320		5						
2025		100			5	(133)					(133)
2026		100			5	(180)					(180)
2027		100			5			100	965	30	
2028	300		200	80	5	(174)		100			(174)
2029			5		5			100	80	50	
2030					5			100			(177)
2031			5		5		222	100			
2032					5			100			
2033									5		
2034	111					(177)					
2035	300						300				
2036											
2037	111										
2038											
Nameplate Total (MW)	822	600	1,170	80	50	(1,026)	522	600	1,170	80	1,026
B2H	–						500				
Net Build	1,696						1,846				

	Portfolio 9						Portfolio 21					
Gas Assumption:	High Gas Price Forecast						High Gas Price Forecast					
Carbon Assumption:	Zero Carbon Price Forecast						Zero Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			520									
2022												
2023			120		5							
2024												
2025					5	(133)						(133)
2026					5							
2027			40	30	5							
2028					5							
2029			80	30	5							
2030			320									
2031					5							
2032					5				520			
2033		100			5			100	240			
2034	300	100			5	(708)		100	40	30	5	(708)
2035	411	100	85	20			300	100	245	50	5	
2036		100						100			5	
2037		100						100			5	
2038	56						111	100			5	
Nameplate Total (MW)	767	500	1,165	80	50	(1,026)	411	600	1,045	80	25	(1,026)
B2H	–						500					
Net Build	1,536						1,635					

	Portfolio 10						Portfolio 22						
Gas Assumption:	High Gas Price Forecast						High Gas Price Forecast						
Carbon Assumption:	Planning Carbon Price Forecast						Planning Carbon Price Forecast						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Nuclear**	**Demand Response**	**Coal Exit**
2019						(127)							(127)
2020						(58)							(58)
2021			480										
2022			120										
2023					5								
2024													
2025			40	30		(133)							(133)
2026			40	20									
2027			360										
2028		100	120	30									
2029		100											
2030		100	5		5								
2031		100			5								
2032		100			5			100	480				
2033		100			5			100	240				
2034					5	(708)		100	80	20			(708)
2035	600		5		5		300	100	245	60		5	
2036	300							100				5	
2037								100				5	
2038											60	5	
Nameplate Total (MW)	900	600	1,170	80	35	(1,026)	300	600	1,045	80	60	20	(1,026)
B2H	–						500						
Net Build	1,759						1,579						

	Portfolio 11								Portfolio 23					
Gas Assumption:	High Gas Price Forecast								High Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast								Generational Carbon Price Forecast					
B2H Assumption:	No B2H								B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Nuclear**	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019								(127)						(127)
2020								(58)						(58)
2021			480							100	360			
2022		100	360					(177)		100				(177)
2023		100				30	5			100				
2024		100					5			100				
2025								(133)						(133)
2026		200	325	80		30	5							
2027		200				30	5			200	320			
2028		100				30	5	(174)		200	125			(174)
2029		100				30	5			100	40	10		
2030						30	5			100				(177)
2031			5			30	5				160	70		
2032							5							
2033							5	(180)	300					
2034	300							(177)			40			(180)
2035					60					100				
2036					60								5	
2037					60					100	5		5	
2038	111								300				5	
Nameplate Total (MW)	411	900	1,170	80	180	210	50	(1,026)	600	1,200	1,050	80	15	(1,026)
B2H	–								500					
Net Build	1,975								2,419					

	Portfolio 12						
Gas Assumption:	High Gas Price Forecast						
Carbon Assumption:	High Carbon Price Forecast						
B2H Assumption:	No B2H						
	Gas	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**
2019							(127)
2020							(58)
2021			480				
2022		100	400				(177)
2023		100	80				
2024		100		5			
2025	56	200	165	75		5	(133)
2026		200	40	10		5	(180)
2027	111	200		5		5	
2028		100		5	30	5	(174)
2029	56	100			30		
2030						5	(177)
2031	300	100	5			5	
2032						5	
2033						5	
2034						5	
2035	170						
2036						5	
2037							
2038							
Nameplate Total (MW)	692	1,200	1,170	100	60	50	(1,026)
B2H	–						
Net Build	2,246						

	Portfolio 24					
Gas Assumption:	High Gas Price Forecast					
Carbon Assumption:	High Carbon Price Forecast					
B2H Assumption:	B2H in Service 2026					
	Wind	**Solar**	**Battery**	**Pumped Storage**	**Biomass**	**Coal Exit**
2019						(127)
2020						(58)
2021		320				
2022	100					
2023						(177)
2024						
2025						(133)
2026						(180)
2027		160	70			
2028		40	10			(174)
2029						
2030						(177)
2031				500		
2032	100	325				
2033	200	200				
2034	200				30	
2035	200					
2036	200					
2037	200					
2038						
Nameplate Total (MW)	1,200	1,045	80	500	30	(1,026)
B2H	500					
Net Build	2,329					

MANUAL OPTIMIZATION RESULTS (MW)

PGPC (1)	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030				**PGPC B2H (1)**	Bridger Exits 2022, 2026, 2028, 2030			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5	(180)					(180)
2027	111	40	30	5						
2028		40	20	5	(174)					(174)
2029	300			5						
2030				5	(177)		40	30	5	(177)
2031	300			5		300			5	
2032				5					5	
2033		40	10						5	
2034		80	20				40	20	5	
2035	56						80	20	5	
2036	56						120	10	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	320	80	50	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	357					410				

PGPC (2)	Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034				**PGPC B2H (2)**	Bridger Exits 2022, 2028, 2034, 2034			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028		40	30	5	(180)					(180)
2029	300			5						
2030				5					5	
2031		40	20	5					5	
2032		40	10	5					5	
2033		80	20						5	
2034	56				(351)		40	30	5	(351)
2035	411					300	160	30	5	
2036	56						80	20	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	320	80	50	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	375					410				

PGPC (3)	Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034	PGPC B2H (3)	Bridger Exits 2022, 2026, 2034, 2034
	Gas Assumption:	Planning Gas Price Forecast		Planning Gas Price Forecast
	Carbon Assumption:	Planning Carbon Price Forecast		Planning Carbon Price Forecast
	B2H Assumption:	No B2H		B2H in service 2026

	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5	(180)					(180)
2027	300			5						
2028		40	30	5						
2029				5						
2030				5					5	
2031		40	20	5					5	
2032		40	10	5					5	
2033		80	20						5	
2034	56				(351)		40	30	5	(351)
2035	411					300	160	30	5	
2036	56						80	20	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	520	80	30	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	537					410				

PGPC (4)	Scenario 4 Assumption:	Bridger Exits Vary				**PGPC B2H (4)**	Bridger Exits Vary			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)					(177)
2023				5			120			
2024				5						
2025				5	(133)					(133)
2026				5						(180)
2027				5						
2028		40		5	(180)					(174)
2029	167	80	50	5						
2030		40	10	5					5	(177)
2031	56			5		111	120	50	5	
2032		80	20	5			80	10	5	
2033	111					111			5	
2034					(351)				5	
2035	411					56			5	
2036	56						80	20	5	
2037	56					56	40		5	
2038	56					56			5	
Nameplate Total (MW)	911	360	80	50	(1,026)	389	440	80	45	(1,026)
B2H	–					500				
Net Build	375					428				

PGHC (1)	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030					**PGHC B2H (1)**	Bridger Exits 2022, 2026, 2028, 2030				
	Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast				
	Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
	B2H Assumption:	No B2H						B2H in service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5	(180)						(180)
2027			280	50	5						5	
2028			80	20	5	(174)					5	(174)
2029	300				5							
2030					5	(177)					5	(177)
2031	111		600	10	5		56		200	80	5	
2032	56				5				160		5	
2033	300								320		5	
2034								400	360		5	
2035							56				5	
2036							56				5	
2037							56				5	
2038		600	80				56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

			PGHC B2H (2)	
PGHC (2)	Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034	**PGHC B2H (2)**	Bridger Exits 2022, 2028, 2034, 2034
	Gas Assumption:	Planning Gas Price Forecast		Planning Gas Price Forecast
	Carbon Assumption:	High Carbon Price Forecast		High Carbon Price Forecast
	B2H Assumption:	No B2H		B2H in service 2026

	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5							
2027					5						5	
2028			40		5	(180)					5	(180)
2029			440	80	5							
2030	300		480		5						5	
2031					5						5	
2032					5						5	
2033											5	
2034	300	400				(351)			40	30	5	(351)
2035	56		80				111	400	1,000	50	5	
2036	56	200					56				5	
2037	56						56				5	
2038							56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

PGHC (3)	Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034					**PGHC B2H (3)**	Bridger Exits 2022, 2026, 2034, 2034				
	Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast				
	Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
	B2H Assumption:	No B2H						B2H in service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5	(180)						(180)
2027			160	70	5						5	
2028			120	10	5						5	
2029			200		5							
2030			480		5						5	
2031	300				5						5	
2032					5						5	
2033											5	
2034						(351)			40	30	5	(351)
2035	300	400	80				111	400	1,000	50	5	
2036	56						56				5	
2037	56	200					56				5	
2038	56						56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

PGHC (4)	Scenario 4 Assumption:	Bridger Exits Vary				PGHC B2H (4)	Bridger Exits Vary			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	High Carbon Price Forecast					High Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5					5	
2024				5					5	
2025				5	(133)				5	(133)
2026				5	(180)				5	(180)
2027	56	80	50	5					5	
2028		80	20	5	(174)				5	(174)
2029	167	120	10	5					5	
2030				5	(177)				5	
2031	300	240		5			40	30	5	
2032				5			40	20	5	
2033	111						80	20		
2034							80	10		(177)
2035	56					222	40			
2036	56					56				
2037	56					56	40			
2038		440					280			
Nameplate Total (MW)	800	1,080	80	50	(1,026)	333	720	80	50	(1,026)
B2H	–					500				
Net Build	984					657				

HGHC (1)			**HGHC B2H (1)**	
	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030		Bridger Exits 2022, 2026, 2028, 2030
	Gas Assumption:	High Gas Price Forecast		High Gas Price Forecast
	Carbon Assumption:	High Carbon Price Forecast		High Carbon Price Forecast
	B2H Assumption:	No B2H		B2H in service 2026

	HGHC (1) Wind	HGHC (1) Solar	HGHC (1) Battery	HGHC (1) Geothermal	HGHC (1) Nuclear	HGHC (1) Pumped Storage	HGHC (1) Biomass	HGHC (1) Demand Response	HGHC (1) Coal Exit	HGHC B2H (1) Wind	HGHC B2H (1) Solar	HGHC B2H (1) Battery	HGHC B2H (1) Geothermal	HGHC B2H (1) Nuclear	HGHC B2H (1) Biomass	HGHC B2H (1) Demand Response	HGHC B2H (1) Coal Exit
2019									(127)								(127)
2020									(58)								(58)
2021																	
2022		120							(177)		120						(177)
2023								5								5	
2024								5								5	
2025								5	(133)							5	(133)
2026								5	(180)							5	(180)
2027		200	50					5								5	
2028		80	30					5	(174)							5	(174)
2029	1,200	760		30			30	5								5	
2030				30			30	5	(177)							5	(177)
2031						500		5			320	80	30		30	5	
2032								5			200					5	
2033																	
2034										100	520						
2035										500			30				
2036										500					30		
2037					60					100				60			
2038					60									60			
Nameplate Total (MW)	1,200	1,160	80	60	120	500	60	50	(1,026)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	–									500							
Net Build	2,504									2,204							

HGHC (2)	Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034	**HGHC B2H (2)**	Bridger Exits 2022, 2028, 2034, 2034
	Gas Assumption:	High Gas Price Forecast		High Gas Price Forecast
	Carbon Assumption:	High Carbon Price Forecast		High Carbon Price Forecast
	B2H Assumption:	No B2H		B2H in service 2026

	Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit	Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019									(127)								(127)
2020									(58)								(58)
2021																	
2022		120							(177)		120						(177)
2023								5								5	
2024								5								5	
2025								5	(133)							5	(133)
2026								5								5	
2027								5								5	
2028		40						5	(180)							5	(180)
2029		400	80					5								5	
2030		360						5								5	
2031	200	240		30				5								5	
2032	300						30	5								5	
2033	600			30													
2034						500			(351)		40						(351)
2035											1,000	80	60		60		
2036							30			1,100							
2037					60					100				60			
2038					60									60			
Nameplate Total (MW)	1,100	1,160	80	60	120	500	60	50	(1,026)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	–									500							
Net Build	2,104									2,204							

HGHC (3)		
	Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034
	Gas Assumption:	High Gas Price Forecast
	Carbon Assumption:	High Carbon Price Forecast
	B2H Assumption:	No B2H

	Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit
2019									(127)
2020									(58)
2021									
2022		120							(177)
2023								5	
2024								5	
2025								5	(133)
2026								5	(180)
2027		160	70					5	
2028		120	10					5	
2029		200						5	
2030		320					30	5	
2031	200	240		30				5	
2032	300						30	5	
2033	600			30					
2034						500			(351)
2035									
2036									
2037	100				60				
2038					60				
Nameplate Total (MW)	1,200	1,160	80	60	120	500	60	50	(1,026)
B2H	–								
Net Build	2,204								

HGHC B2H (3)	
	Bridger Exits 2022, 2026, 2034, 2034
	High Gas Price Forecast
	High Carbon Price Forecast
	B2H in service 2026

	Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019								(127)
2020								(58)
2021								
2022		120						(177)
2023							5	
2024							5	
2025							5	(133)
2026							5	(180)
2027							5	
2028							5	
2029							5	
2030							5	
2031							5	
2032							5	
2033								
2034		40						(351)
2035		1,000	80	60		60		
2036	1,100							
2037	100				60			
2038					60			
Nameplate Total (MW)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	500							
Net Build	2,204							

HGHC (4)

Scenario 4 Assumption: Bridger Exits Vary
Gas Assumption: High Gas Price Forecast
Carbon Assumption: High Carbon Price Forecast
B2H Assumption: No B2H

	Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit
2019									(127)
2020									(58)
2021									
2022		120							(177)
2023								5	
2024								5	
2025								5	(133)
2026								5	(180)
2027						500		5	
2028								5	(174)
2029								5	
2030								5	(177)
2031		160	70		60			5	
2032	100	80	10					5	
2033					60				
2034		200							
2035		200		30					
2036					60				
2037	200	200					30		
2038	800	200							
Nameplate Total (MW)	1,100	1,160	80	30	180	500	30	50	(1,026)
B2H	–								
Net Build	2,104								

HGHC B2H (4)

Bridger Exits Vary
High Gas Price Forecast
High Carbon Price Forecast
B2H in service 2026

	Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019								(127)
2020								(58)
2021								
2022		120						(177)
2023							5	
2024							5	
2025							5	(133)
2026							5	(180)
2027							5	
2028							5	(174)
2029							5	
2030							5	(177)
2031		160	70		60		5	
2032	100	80	10				5	
2033		240						
2034					60			
2035		160		30				
2036	200	160				30		
2037	100				60			
2038	700	240						
Nameplate Total (MW)	1,100	1,160	80	30	180	30	50	(1,026)
B2H	500							
Net Build	2,104							

OREGON CARBON EMISSION FORECAST

Idaho Power anticipates the 2019 IRP carbon emission forecast will be used to establish a target for Idaho Power compliance with the proposed Oregon Cap and Trade Legislation. Idaho Power carefully reviewed historical emissions and emissions assumptions in the portfolio modeling and output.

The Total Carbon Dioxide (CO_2) Emissions forecast is composed of results from the AURORA modeling, policy adjustments to IRP forecast assumptions and a Market Volatility adjustment. The modeled AURORA resource dispatch from Idaho Power's preferred resource portfolio, Portfolio 14, is the basis for the emissions forecast. The AURORA emissions forecast consists of the emissions from the modeled operation of Idaho Power's resources and emissions based on forecasted purchased energy. Emissions from forecasted purchased energy is estimated to contribute 0.47 short tons per MWh, which is in-line with the unspecified market purchases used by the California Air Resource Board in their Cap and Trade program.

The hydro forecast in the 2019 IRP AURORA modeling assumes future increases in hydro generation based on expansion of Idaho Power's cloud seeding program and certain State of Idaho groundwater management activities. The actual results from these hydro generation programs may not result in the forecasted increase in generation. Cloud seeding expansion is subject to regulatory review and funding and therefore, was removed from carbon forecast modeling. Groundwater management activities, such as managed aquifer recharge has exceeded the State of Idaho's goals in 2017 and 2018, resulting in reduced wintertime hydro generation production. Idaho Power is concerned that trend may continue and thus feels that carbon forecast modeling should use a more conservative hydrogeneration assumption.

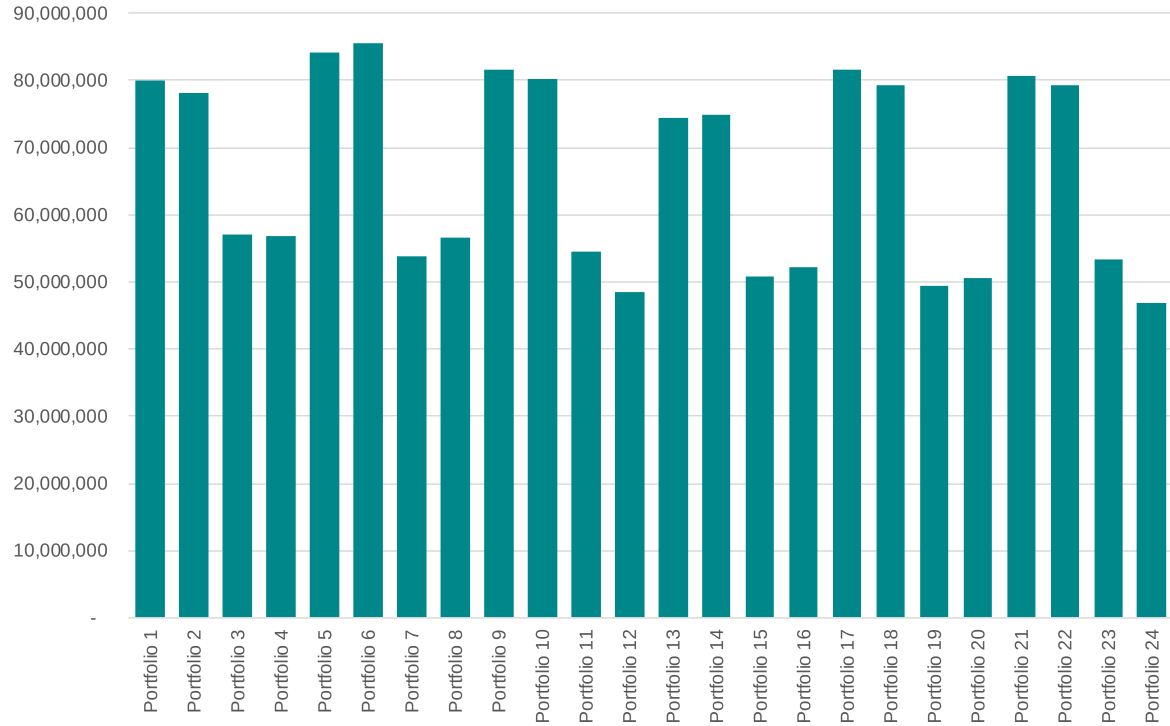
Lastly, Idaho Power reviewed recent system operations, resource dispatch and associated carbon emissions as well as the near-term operational forecasts. This review resulted in an Market Forecast Volatility adjustment to reconcile the discrepancy in emissions forecasts between the IRP and near-term operational planning. Examples of events that may drive market volatility: unplanned system outages (Idaho Power's system and surrounding system), extreme weather events, supply interruptions or limitations, natural disaster, etc.

Year	Resource CO_2 Emissions	Market Purchases CO_2	Hydro Policy Implementation Uncertainty Adjustment	Market Volatility Adjustment	Total System CO_2 Emissions	Oregon CO_2 Emissions
2019	4,100,667	287,475	329,686	190,859	4,908,687	223,856
2020	4,206,718	274,662	481,180	190,859	5,153,420	234,266
2021	4,165,188	350,488	541,259	190,859	5,247,795	237,805
2022	4,423,053	349,999	566,011	190,859	5,529,922	249,326
2023	3,932,304	436,275	586,927	190,859	5,146,365	230,902
2024	3,932,231	535,493	609,505	190,859	5,268,088	234,467
2025	4,323,190	524,129	617,935	190,859	5,656,114	250,654
2026	3,935,017	792,624	626,016	–	5,353,657	236,474
2027	3,535,890	879,349	631,418	–	5,046,658	222,285
2028	3,538,173	1,003,592	637,980	–	5,179,745	227,147
2029	2,345,650	1,480,651	643,882	–	4,470,182	195,093
2030	2,610,779	933,734	646,328	–	4,190,841	182,229
2031	1,687,670	1,432,465	651,605	–	3,771,741	163,443
2032	1,610,320	1,506,697	659,269	–	3,776,286	163,062
2033	1,671,532	1,599,885	672,911	–	3,944,327	169,880
2034	1,678,076	1,610,612	682,302	–	3,970,991	170,314
2035	1,848,815	1,527,210	693,035	–	4,069,059	173,587
2036	1,843,975	1,588,386	708,991	–	4,141,353	175,661
2037	1,833,284	1,550,450	687,647	–	4,071,380	171,707
2038	1,787,418	998,475	678,607	–	3,464,501	145,355

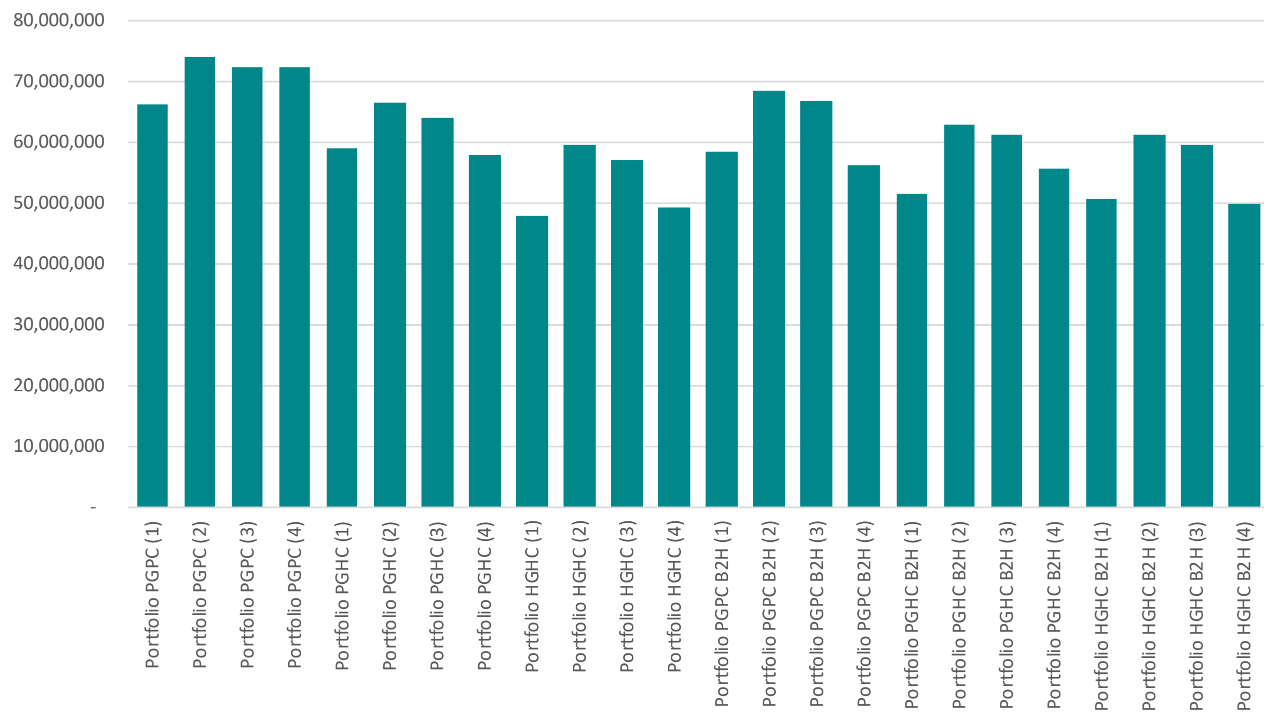
PORTFOLIO GENERATING RESOURCE EMISSIONS

CO_2 Tons

WECC-Optimized Portfolios

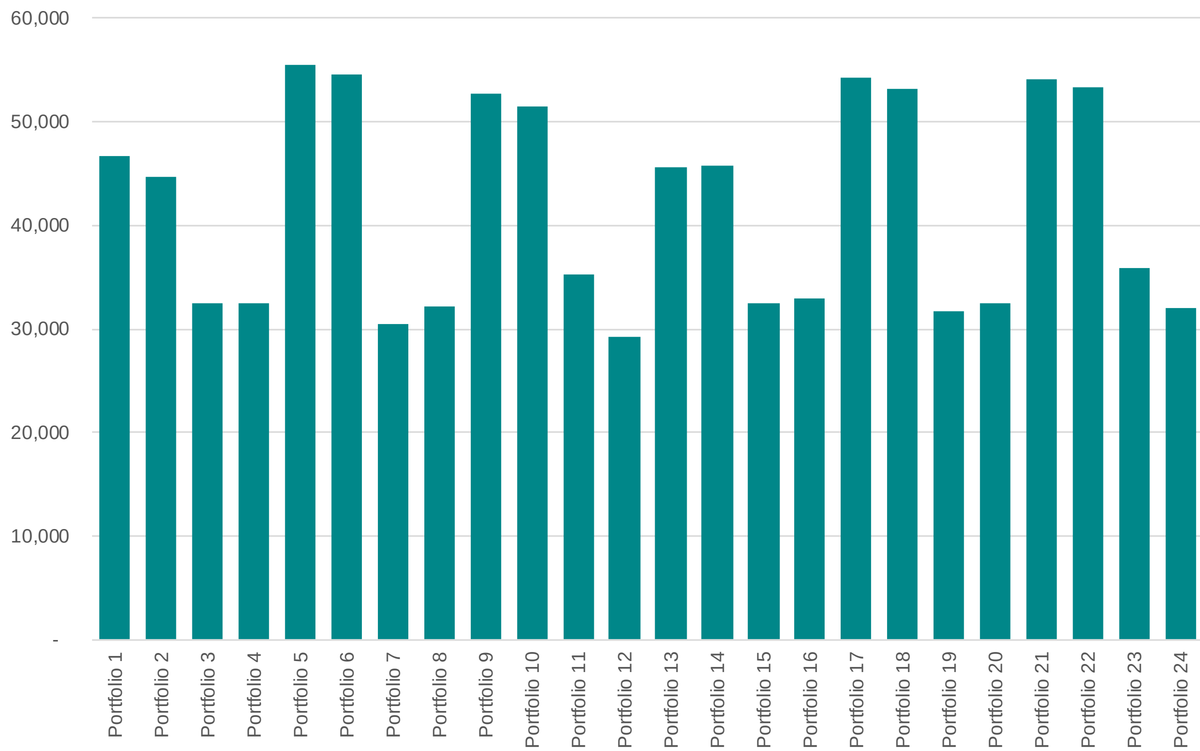


Idaho Power-Specific Portfolios

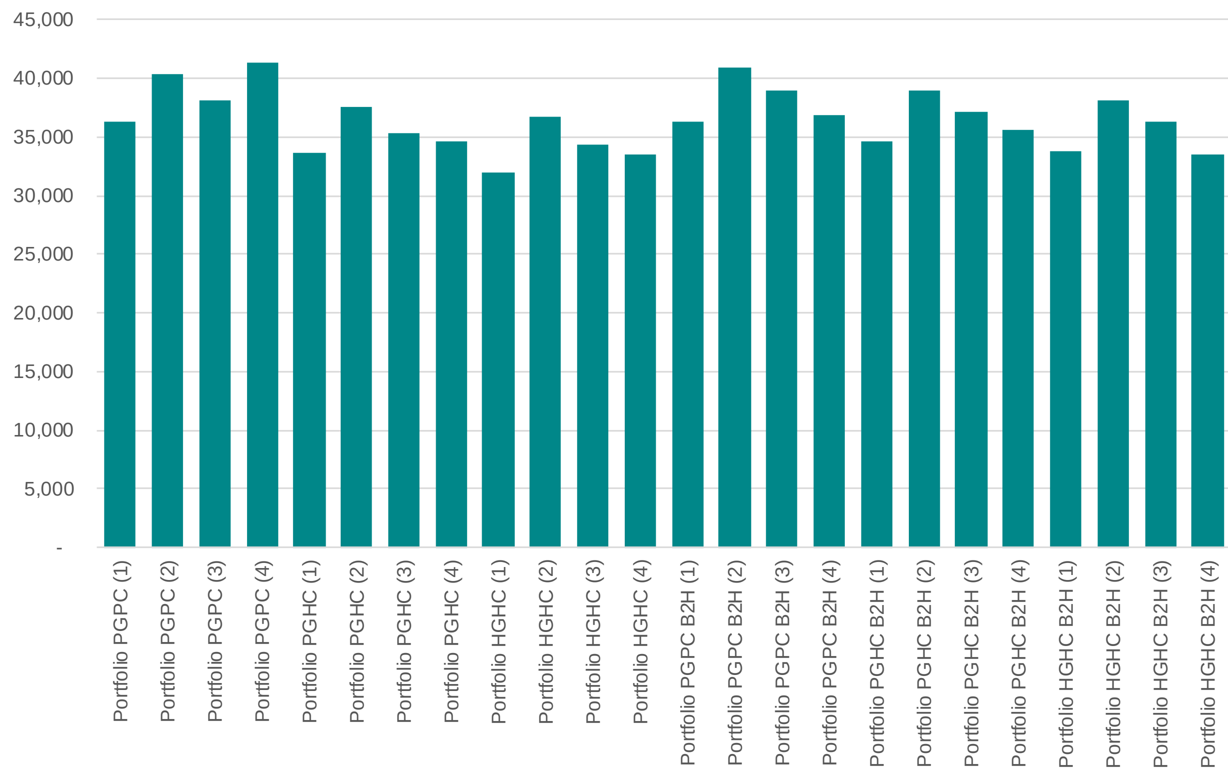


NOx Tons

WECC-Optimized Portfolios

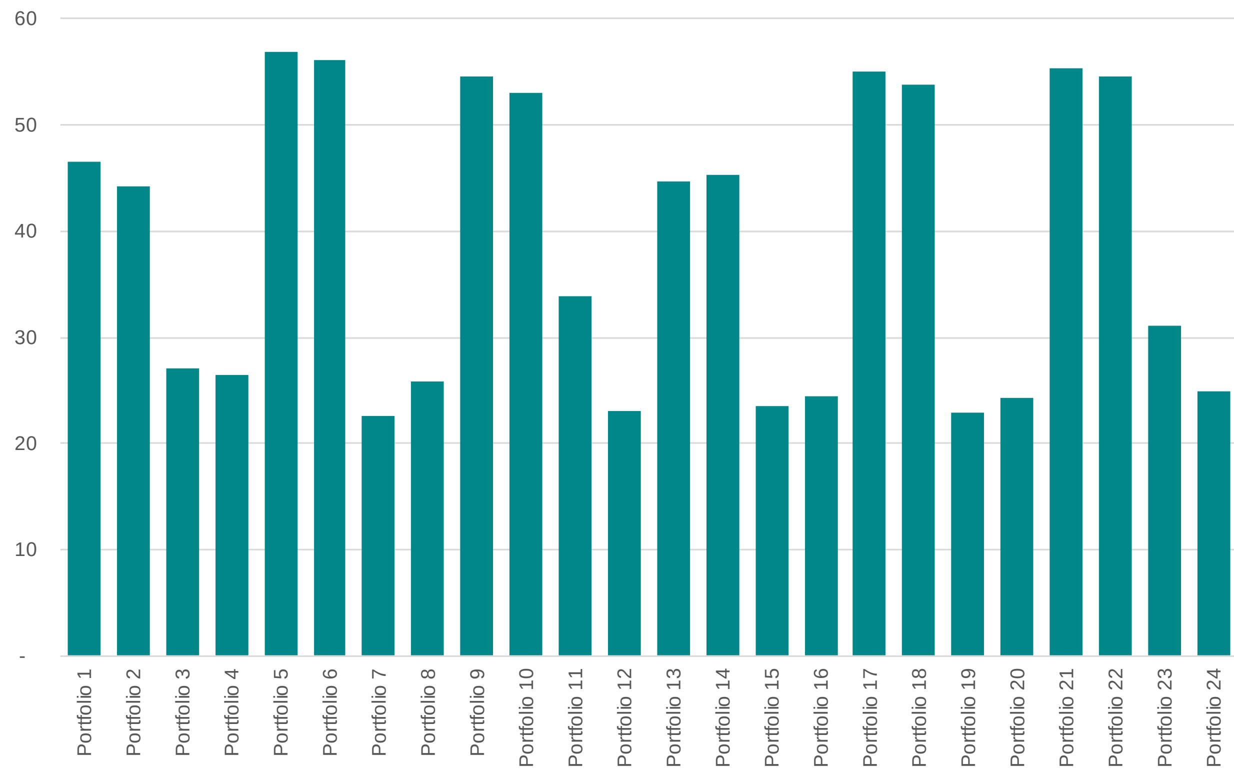


Idaho Power-Specific Portfolios

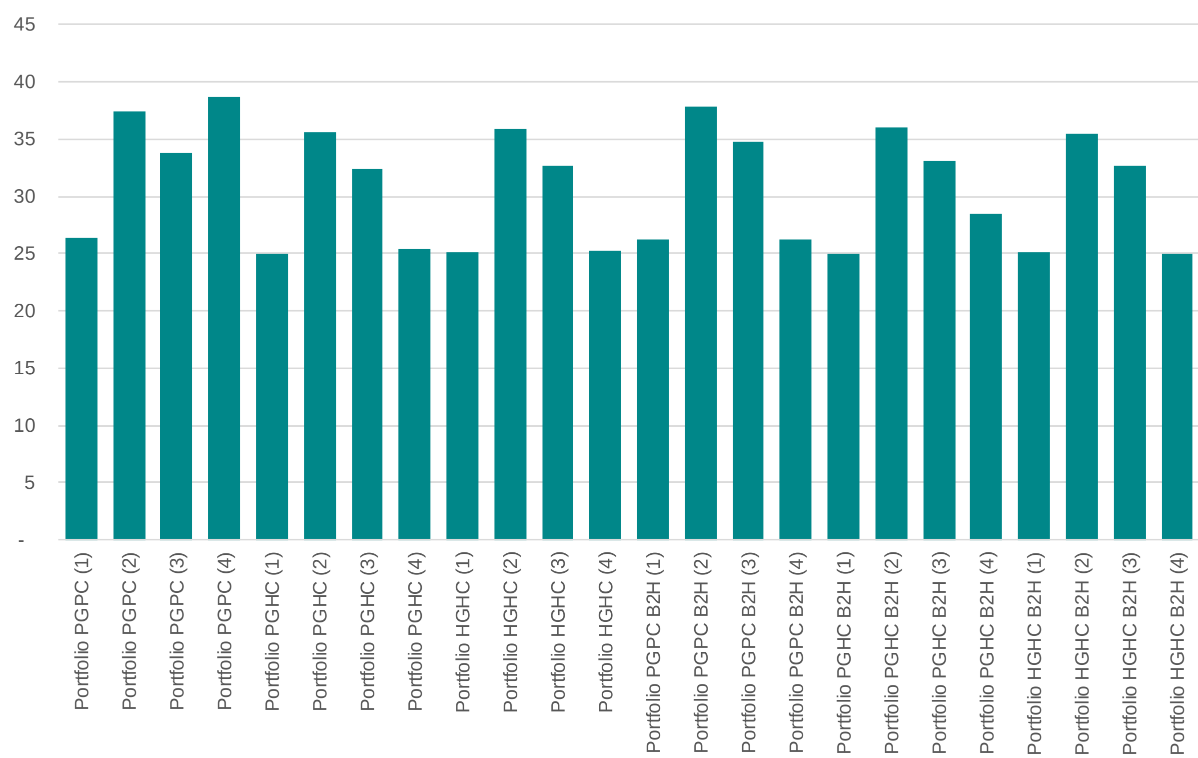


HG Tons

WECC-Optimized Portfolios

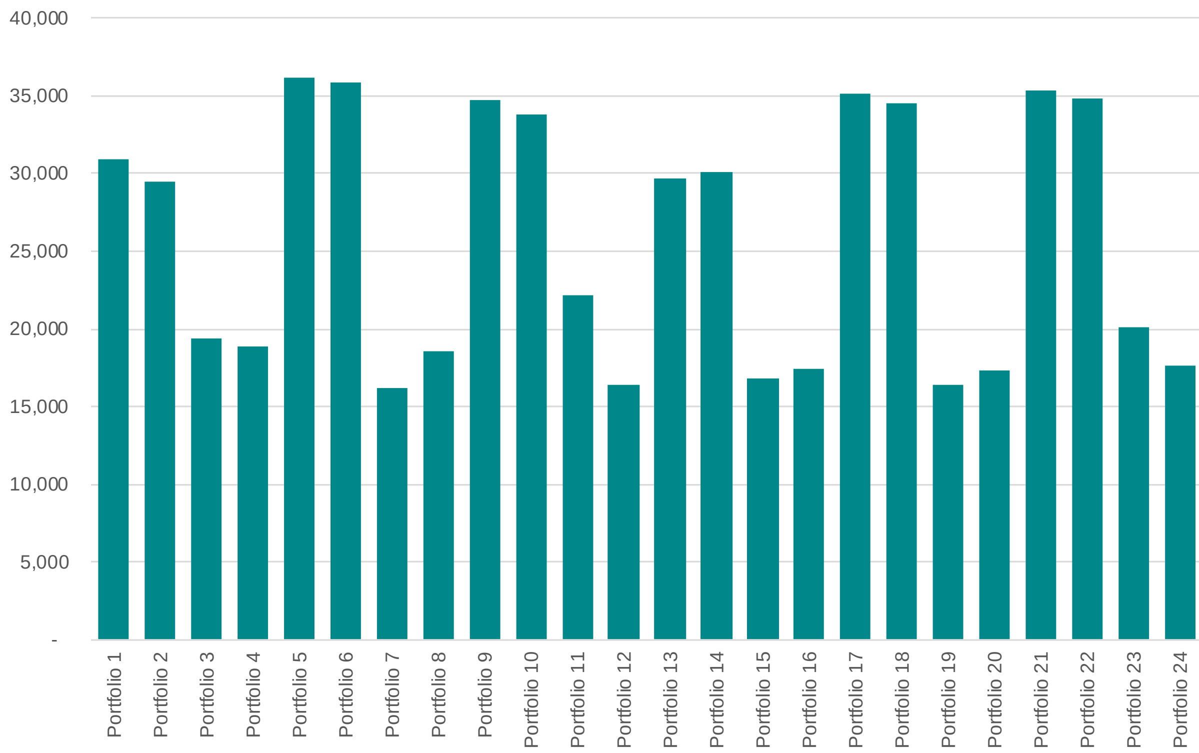


Idaho Power-Specific Portfolios

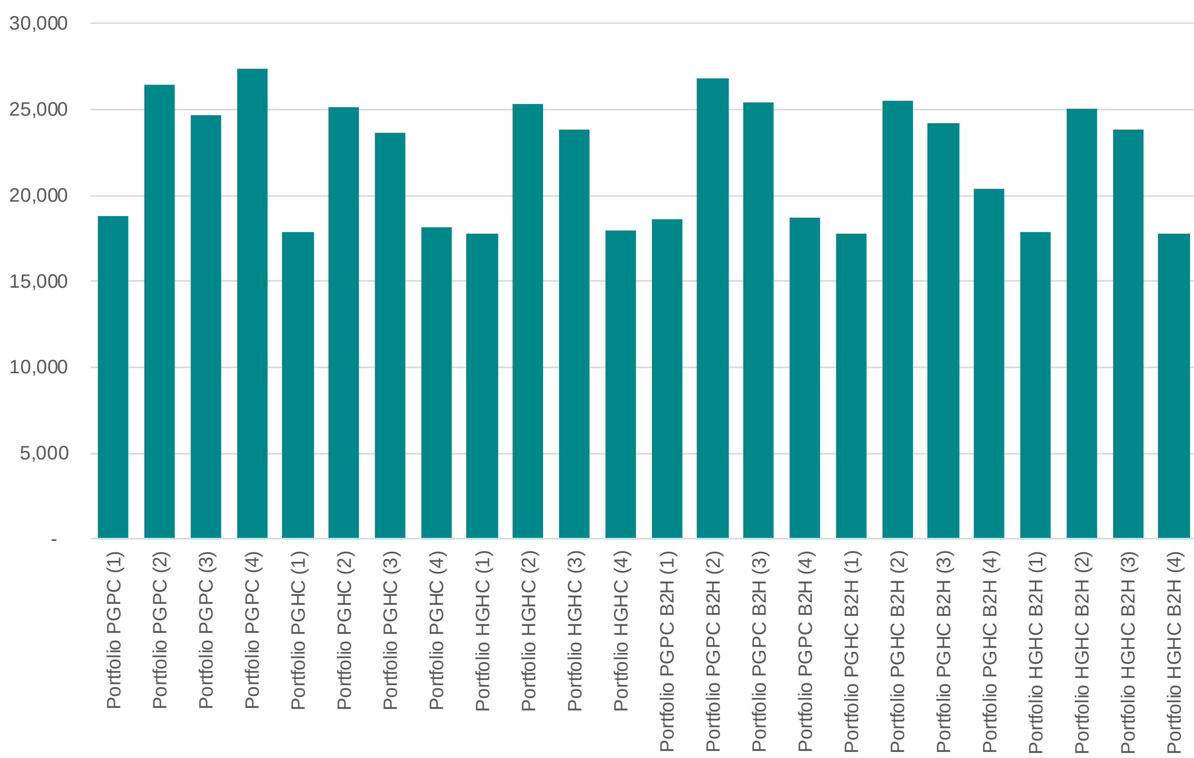


SO_2 Tons

WECC-Optimized Portfolios



Idaho Power-Specific Portfolios



COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

Compliance with State of Oregon EV Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluation on a consistent and comparable basis.
   - All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of poweror gas purchases, transportation, and storageand demand side options which focus on conservation and demand response.
   - Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.

Idaho Power response:

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 3. Idaho Power Today;* demand-side options are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning*.

New resource options including fuel types, technologies, lead times, in-service dates, durations and locations are described in *Chapter 4. Future Supply-side Generation and Storage Resources*, *Chapter 5. Demand-Side resources*, *Chapter 6. Transmission Planning*, and *Chapter 7. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and *Chapter 9. Modeling Analysis and Result—Planning Case Portfolio Analysis*.

The WACC rate used to discount all future resource costs is discussed in the Technical Appendix *Supply Side Resource Data – Key Financial and Forecast Assumptions*.

b. Risk and uncertainty must be considered.
   - At a minimum, utilities should address the following sources of risk and uncertainty:
     1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.
     2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.
   - Utilities should identify in their plans any additional sources of risk and uncertainty.

Idaho Power response:

Electric utility risk and uncertainty factors (load, natural gas, and water conditions) for resource portfolios are considered in *Chapter 9 Modeling Analysis*. Plant forced outages are modeled in AURORA on a unit basis and are discussed in *Chapter 9 Loss of Load Expectation*. Risk and uncertainty associated with high natural gas and high carbon cost are discussed in *Chapter 9 Portfolio Cost Analysis.*

Additional sources of risk and uncertainty including regional resource adequacy and qualitative risks are discussed in *Chapter 9. Modeling Analysis*.

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.
   - Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.
   - To address risk, the plan should include, at a minimum:
     a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
     b. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.
   - The utility should explain in its plan how its resource choices appropriately balance cost and risk.

Idaho Power response:

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. Summary—Introduction*.

Modeling analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases is discussed in *Chapter 9. Modeling Analysis*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis*.

Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1. IRP Methodology*. Idaho Power's Energy Risk Management Program is designed to systematically identify, quantify and manage the exposure of the company and its customers to the uncertainties related to the energy markets in which the Company is an active participant. The Company's Risk Management Standards limit term purchases to the prompt 18 months of the forward curve.

Idaho Power's plan and how the resource choices appropriately balance cost and risk is presented in *Chapter 10. Preferred Portfolio and Action Plan.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Idaho Power response:

Long-run public interest issues are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*.

Guideline 2: Procedural Requirements

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.

Idaho Power response:

The IRP Advisory Council meetings are open to the public. A roster of the IRP Advisory Council members along with meeting schedules and agendas is provided in the Technical Appendix, *IRP Advisory Council*.

b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

Idaho Power response:

Idaho Power makes public extensive information relevant to its resource evaluation and action plan. This information is discussed in IRP Advisory Council meetings and found throughout the 2019 IRP, the 2019 Load and Sales Forecast and in the 2019 Technical Appendix.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Idaho Power response:

Idaho Power provided copies to members of the IRPAC on Friday, June 7, 2019. The company requested for comments to be provided no later than Friday, June 14, 2019.

Guideline 3: Plan Filing, Review, and Updates

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.

Idaho Power response:

The OPUC acknowledged Idaho Power's 2017 IRP on May 23, 2018 in Order 18-176. The Idaho Power 2019 IRP will be filed by June 30, 2019.

b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

Idaho Power response:

Idaho Power will present the results of the Second Amended 2019 IRP at a public meeting at the OPUC on October 22, 2020.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

Idaho Power response:

No response needed.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

Idaho Power response:

No response needed.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

Idaho Power response:

No response needed.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

Idaho Power response:

Idaho Power submitted its annual update on January 28, 2019. A public meeting was held March 12, 2019 to discuss the 2017 IRP update.

g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:
   - Describes what actions the utility has taken to implement the plan;
   - Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and
   - Justifies any deviations from the acknowledged action plan.

Idaho Power response:

No response needed.

Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements;

Idaho Power response:

Idaho Power provides information on how the company met each requirement in a table is presented in the Technical Appendix and will be provided to the OPUC staff in an informal letter.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

Idaho Power response:

High-growth scenarios at the 90^{th} and 95^{th} percentile levels for peak hour, and at the 70^{th} and 90^{th} percentile levels for energy are provided in *Chapter 7. Planning Period Forecasts*. Stochastic load risk analysis and major assumptions are discussed in *Chapter 9. Modeling Analysis*. Major assumptions are also discussed in *Chapter 7. Planning Period Forecasts.*

c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;

Idaho Power response:

Peaking capacity and energy capability for each year of the plan for existing resources is discussed in *Chapter 7. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Sales and Load Forecast Data* and *Existing Resource Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 8. Portfolios*.

d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;

Idaho Power response:

Not applicable.

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

Idaho Power response:

Supply-side resources are discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources*.

Demand-side resources are discussed in *Chapter 5-Demand-Side Resources*.

Resource costs are discussed in *Chapter 7. Planning Period Forecasts – Analysis of IRP ResourceResource Costs-IRP Resources* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*.

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

Idaho Power response:

Resource reliability is covered in *Chapter 9. Modeling Analysis*

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

Idaho Power response:

Key Assumptions including the natural gas price forecast are discussed in *Chapter 7. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in *Chapter 9. Modeling Analysis – Portfolio Emission Results* and in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*.

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

Idaho Power response:
Resource portfolios considered for the 2019 IRP are described in *Chapter 8. Portfolios*.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

Idaho Power response:
Evaluation of the portfolios over a range of risks and uncertainties is discussed in *Chapter 9. Modeling Analysis*.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

Idaho Power response:
Portfolio cost, risk results, interpretations and the selection of the preferred portfolio are provided in *Chapter 9. Modeling Analysis*.

k. Analysis of the uncertainties associated with each portfolio evaluated;

Idaho Power response:
The quantitative and qualitative uncertainties associated with each portfolio are evaluated in *Chapter 9. Modeling Analysis*.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

Idaho Power response:
The preferred resource portfolio is identified in *Chapter 10. Preferred Portfolio and Action Plan*.

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

Idaho Power response:

Risk associated with the selected portfolio including coal-unit exits is discussed in *Chapter 10. Preferred Portfolio and Action Plan*.

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Idaho Power response:

An action plan is provided in *Chapter 1. Summary—Action Plan* and in *Chapter 10 Preferred Portfolio and Action Plan.*

Guideline 5: Transmission

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

Idaho Power response:

The fuel transportation for each resource being considered is presented in the Technical Appendix, *Cost Inputs and Operating Assumptions*. Transmission assumptions for supply-side resources considered are included in *Chapter 6. Transmission Planning—Transmission assumptions in IRP portfolios*. Transportation for natural gas is discussed in *Chapter 7. Planning Period Forecasts—Natural Gas Price Forecast*.

Guideline 6: Conservation

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.

Idaho Power response:

The contractor-provided conservation potential study for the 2019 IRP and is described in *Chapter 5 Demand-Side Resources – Energy Efficiency Forecasting – Potential Assessment*.

b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

Idaho Power response:

A forecast for energy efficiency effects is provided in Cha*pter 5. Demand-Side Resources*.

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:
   - Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and
   - Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.

Idaho Power response:

Idaho Power administers all its conservation programs except market transformation. Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Appendix B: Idaho Power's Demand-Side Management 2017 Annual Report.* NEEA savings are included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.

Guideline 7: Demand Response

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Idaho Power response:

Demand response resources are evaluated in *Chapter 5. Demand-Side Resources – Changes from the 2017 IRP.*

Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Idaho Power response:

Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio are shown in the Technical Appendix, *Portfolio Analysis, Results, and Supporting Documentation*.

Guideline 9: Direct Access Loads

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Idaho Power response:

Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads.

Guideline 10: Multi-state Utilities

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Idaho Power response:

Idaho Power's analysis was performed on an integrated-system basis discussed in *Chapter 9. Modeling Analysis and Results*. Idaho Power will file the 2019 IRP in both the Idaho and Oregon jurisdictions.

Guideline 11: Reliability

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Idaho Power response:

The capacity planning margin and regulating reserves are discussed in Chapter 8. Portfolios. A loss of load expectation analysis and regional resource adequacy are discussed in *Chapter 9. Modeling Analysis.*

Guideline 12: Distributed Generation

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Idaho Power response:

Distributed generation technologies were evaluated in *Chapter 4. Future Supply-Side Generation and Storage Resources* and in *Chapter 7. Planning Period Forecasts—Analysis of IRP Resources*.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:
   - Identify its proposed acquisition strategy for each resource in its action plan.

- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

Idaho Power response:

Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the rules established by Oregon in Order No. 18-324 issued on August 30, 2018 and codified in Oregon Administrative Rules 860-089-0010-0550.

Idaho Power identifies its proposed acquisition strategy in *Chapter 10. Preferred Portfolio and Action Plan—Action Plan (2019–2026).* Discussion of asset ownership versus market purchases is found in *Chapter 9. Modeling Analysis*.

b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.

Idaho Power response:

Not applicable.

Compliance with EV Guidelines

Guideline 1: Forecast the Demand for Flexible Capacity

Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

Idaho Power response:

A discussion of the 2019 IRP's analysis for the flexibility guideline is provided in *Chapter 8. Portfolios.*

Guideline 2: Forecast the Supply for Flexible Capacity

Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;

Idaho Power response:

A discussion of the planning margin and regulating reserves is found at *Chapter 8. Portfolios.*

Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis

In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Idaho Power response:

The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast, *Company System Load—Electric Vehicles.*

State of Oregon Action Items Regarding Idaho Power's 2017 IRP

Action Item 1: EIM

Continue planning for western EIM participation beginning in April 2018.

Idaho Power response:

Idaho Power joined the western EIM in April 2018.

Action Item 2: Loss-of-load and solar contribution to peak

Investigate solar PV contribution to peak and loss-of-load probability analysis.

Idaho Power response:

Solar PV contribution to peak is discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources – Renewable Resource – Solar*.

Loss-of-load probability analysis is discussed in *Chapter 9. Modeling Analysis – Loss of Load Expectation.*

Action Item 3: North Valmy Unit 1

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.

Idaho Power response:

Idaho Power's action plan continues to target 2019 as the exit date from North Valmy Unit 1. Idaho Power's exit from Valmy Unit 1 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

The assessment of import dependability from northern Nevada is discussed in *Chapter 6. Transmission Planning – Nevada without North Valmy.*

Action Item 4: Jim Bridger Units 1 and 2

Plan and negotiate with PacifiCorp and regulators to achieve earl retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.

Idaho Power response:

Idaho Power's 2019 IRP Action Plan is detailed in Chapter 10. Action Plan (2019-2026) and includes updated target dates for early exits during 2022 and 2026. Discussion of the modeling analysis to reach these target dates is at *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources-Coal Resources – Jim Bridger.* Discussion of risks related to these planning and negotiating actions is discussed in *Chapter 9. Modeling Analysis – Qualitative Risk Analysis.*

Action Item 5: B2H

Conduct ongoing permitting, planning studies, and regulatory filings.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 6: B2H

Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 7: Boardman

Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.

Idaho Power response:

Idaho Power's action plan continues to target 2020 as the exit date from Boardman. Idaho Power's exit from Boardman is discussed in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – Boardman*.

Action Item 8: Gateway West

Conduct ongoing permitting, planning studies, and regulatory filings.

Modifications: Idaho Power should provide additional information to the Commission on an ongoing basis on Energy Gateway's progress, Idaho Power's inclusion of it as a least-cost/least risk portfolio, the status of co-participants and Energy Gateway's role in the IRP.

Idaho Power response:

Discussion regarding Gateway West is found in *Chapter 6. Transmission Planning – Gateway West*.

Idaho Power files quarterly transmission updates regarding the Energy Gateway West transmission project and updates on the permitting or completion of the Boardman to Hemingway transmission line project with the OPUC in Docket RE 136. The transmission update for Q4 2018 was filed on January 15th, 2019 and the update for Q1 2019 was filed on April 30, 2019.

Action Item 9: Energy Efficiency

Continue the pursuit of cost-effective energy efficiency.

Modifications: In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology.

Idaho Power response:

Idaho Power's energy efficiency opportunities and improvements to its avoided cost methodology are discussed in *Chapter 5. Demand-side Resources*.

Action Item 10: Carbon emission regulations

Continue stakeholder involvement in CAA Section 111(d) proceeding, or alternative regulations affecting carbon emissions.

Modifications: Idaho Power will provide a report as part of its 2019 IRP filing describing the risks to the company and its customers associated with climate change.

Idaho Power response:

Idaho Power continues to participate in carbon emission discussions and announced our Clean Energy Goal in March 2019. These efforts are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*. Modeling of carbon regulation is discussed *in Chapter 8. Portfolios – Framework for Expansion Modeling – Carbon Price Forecasts*.

Action Item 11: North Valmy Unit 2

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operation by year-end 2025.

Idaho Power response:

Idaho Power's exit from Valmy Unit 2 is discussed in *Chapter 1. Summary – Action Plan – Valmy Unit 2 Exit Date*.

Other Item 1: 2019 IRP Preview

Idaho Power is required that five months prior to the filing of the 2019 IRP, Idaho Power file a report in this docket providing the following information:

- Comprehensive update of the B2H project.
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast.
- A discussion of portfolio modeling options and preferences for the 2019 IRP.
- An update on Jim Bridger environmental control developments and options.
- Updates as requested by Staff.

Idaho Power response:

Idaho Power's filed the updated IRP Report with the OPUC on January 28, 2019.

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INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED

OCTOBER • 2020

APPENDIX D: B2H SUPPLEMENT

SAFE HARBOR STATEMENT

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EXECUTIVE SUMMARY

The Boardman to Hemingway Transmission Line Project (B2H) is a planned 500-kilovolt (kV) transmission project that would span between the Hemingway 500-kV substation near Marsing, Idaho, and the proposed Longhorn Station near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. Idaho Power's planned capacity interest in B2H will increase the availability of capacity and energy from the Pacific Northwest market by 500 megawatts (MW) during the summer months, when energy demand from Idaho Power's customers is at its highest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's integrated resource plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the 2019 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new combined-cycle gas plant, or a new utility-scale solar complex.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. As can be seen in the *Second Amended 2019 IRP*, the lowest-cost resource portfolio includes B2H. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational flexibility.

In addition to being the least-cost, lowest-risk resource to meet Idaho Power' resource needs, the B2H project has received national recognition for the benefits it will provide. 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. Most recently, B2H was acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,[1] B2H was held up as a "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…" The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.

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

Under the B2H Permit Funding agreement, Idaho Power is funding 21.2-percent of the permitting costs for the project, with PacifiCorp and Bonneville Power Administration (BPA) funding the remainder of those costs. With permitting nearing completion, the three entities are currently negotiating potential construction and ownership agreements to complete the project. Working with coparticipants will allow Idaho Power customers to benefit from the project's economies of scale and from load diversity between the coparticipants. While Idaho Power's 21.2-percent share would provide for an annual average of 350 MW of west-to-east import capacity, the agreement is structured to provide Idaho Power with 500 MW of import capacity during the summer months, when Idaho Power experiences peak demand, and 200 MW of import capacity in the winter months, when the load-serving need is less.

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20 percent contingency for unforeseen expenses. In the *Second Amended 2019 IRP*, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million in B2H project expenses. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly 10 years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017. The BLM ROD formalized the conclusion of the siting process at the federal level, as required by the *National Environmental Policy Act of 1969* (NEPA). The BLM ROD provides the ability to site the B2H project on BLM-administered land. Idaho Power also received a ROD from the U.S. Forest Service in 2018 and a ROD from the U.S. Navy in 2019.

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy in summer 2017. The Oregon Department of Energy issued a Proposed Order on July 2, 2020 that recommends approval of the project to Oregon's Energy Facility Siting Council (EFSC). Following the Proposed Order, the EFSC will conduct a contested case proceeding on the Proposed Order. The EFSC is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[2] Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate

[2] See generally Oregon Revised Statute (ORS) 469.300-469.563, 469.590-469.619, and 469.930-469.992.

a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based in part on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company's IRP.[3] The OPUC has already acknowledged the construction of B2H in Idaho Power's 2017 IRP. In this case, Idaho Power again seeks to confirm its acknowledgement of B2H as reflected in the *Second Amended 2019 IRP*.

As of the date of this report, Idaho Power expects the Oregon Department of Energy (ODOE) to issue a Final Order and Site Certificate in 2021. To achieve a 2026 in-service date, as shown in the near-term Action Plan, preliminary construction activities must commence in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) acquisition activities, and detailed design and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

This B2H appendix to the *Second Amended 2019 IRP* provides context and details that support evaluating this transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

[3] OAR 345-023-0020(2). Idaho Power is also requesting satisfaction of the need standard under EFSC's System Reliability Rule, OAR 345-023-0030.

Resource Need Evaluation

Resource Needs and Capacity Expansion Modeling

A 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 which were quantifiably demonstrated to eliminate the identified resource deficiencies, and qualitatively varied by resource type, where the varied resource types considered reflected the company's understanding that the financial performance of a resource class is dependent on future conditions in energy markets and energy policy.

Idaho Power received comments on the 2017 IRP encouraging the use of capacity expansion modeling for *Second Amended 2019 IRP* portfolio development. In response to this encouragement, the company elected to use the AURORA model's capacity expansion modeling capability to develop portfolios for the *Second Amended 2019 IRP*. Under this process, the alternative future scenarios are formulated first, and then the AURORA model is used to develop portfolios that are optimal to the selected alternative future scenarios. For example, the AURORA model can be expected under an alternative future scenario having high natural gas price and/or high cost of carbon to develop a portfolio having substantial expansion of non-carbon emitting variable energy resources, as such a portfolio is likely well fit for such a scenario.

The use of capacity expansion modeling has resulted in a departure from the 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 *Second Amended 2019 IRP*, the AURORA model selects from the variety of supply- and demand-side resource options available to it to develop portfolios that are optimal for the given alternative future scenarios with the objective of meeting a 15 percent planning margin and regulating reserve requirements associated with balancing load, wind plant output, and solar plant output. The model can also simulate retirement of existing generation units if economical as well as build resources that are economic absent a defined capacity need. The capacity expansion modeling process is discussed in further detail in Chapter 8 of Idaho Power's *Second Amended 2019 IRP*.

In meeting the objectives for planning margin and regulating reserve requirements, the AURORA model accounts for the capability of the existing system to meet the objectives and only selects from the pool of new supply- and demand-side resource options 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, such as that provided by B2H. Existing demand-side resources include current levels of demand response and savings from current energy efficiency programs and measures.

IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the Public Utility Commission of Oregon (OPUC) adopted guidelines regarding integrated resource planning.[4]

> Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation *and electric transmission facilities as resource options*, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving *reliability*.

Boardman to Hemingway as a Resource

The Boardman to Hemingway Transmission Line Project (B2H) is one of the most cost-effective IRP resources Idaho Power has considered as proven through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the capacity cost of the project (capital and other fixed costs) and 2) the energy cost of the project (variable costs). Capital costs are derived through cost estimates to install the various projects. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc.

Illustrating the difference between capacity and energy, a diesel generator may have a very low cost to install; however, the cost of diesel fuel and the maintenance required would be significant. Alternatively, a utility-scale solar plant will have almost no energy cost; the fuel to run the plant—the sun—is free. However, in the case of a solar plant, the capacity cost to install the plant, while continuing its declining trend, can still be relatively expensive, particularly when considered in terms of cost per unit of *on-peak* capacity.

Capacity Costs

Table 1 below provides capital costs for resource options found in the *Second Amended 2019 IRP* to have the lowest cost from a capacity perspective. Capital costs in Table 1 are provided in base year 2023 dollars. The use of 2023 as base year allows the analysis to capture declining

[4] apps.puc.state.or.us/orders/2007ords/07-002.pdf

capital cost trends for solar resources. The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H.

Table 1. Total capital $/kW for select resources considered in the 2019 IRP (2023$)

Resource Type	Total Capital $/kW	Total Capital $/kw—peak	Depreciable Life
B2H	$894*	$626**	55 years
Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 megawatts [MW])	$1,294	$1,294	30 years
Simple-cycle combustion turbine — Frame F Class (170 MW)	$1,142	$1,142	35 years
Reciprocating Gas Engine (111.1 MW)	$1,087	$1,087	40 years
Solar Photovoltaic (PV)—Utility-Scale 1-Axis	$1,498	$3,329***	30 years

* Uses the B2H 350-MW average capacity

** Uses the B2H 500-MW capacity

***Uses on-peak capacity of 45 percent of installed nameplate capacity

The B2H total capital cost per kilowatt at peak is roughly 60 percent of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to at most 40 years for a gas plant or 30 years for a solar plant. The low up-front cost and slower depreciation further reduces the cost impact to Idaho Power's customers. Finally, the B2H cost estimate includes a 20 percent contingency, whereas none of the other resources evaluated in the *Second Amended 2019 IRP* includes a cost contingency. The summation of these factors suggest B2H is the lowest capital-cost resource by a substantial margin.

Energy Cost

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub at both peak times and when energy prices are favorable relative to the costs of Idaho Power's existing resource fleet. Referencing Figure 7.6 in the *Second Amended 2019 IRP*, the B2H project has the lowest levelized cost of energy relative to other resource options evaluated in the *Second Amended 2019 IRP*.

Market Overview

Power Markets

A power market hub is an aggregation of transaction points (often referred to as bus points or buses). Hubs create a common point to buy and sell energy, creating one transaction point for bilateral transactions. Hubs also create price signals for geographical regions.

Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.
2. Reliable contractual standards exist for the delivery and receipt of the energy.
3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

Mid-C Market

The Mid-C electric energy market hub is a hub where power is transacted both physically and financially (derivative). Power is traded both physically and financially in different blocks: long term, monthly, balance-of-month, day ahead, and hourly. Much of the activity for balance-of-month and beyond is traded and cleared through a clearing exchange, the Intercontinental Exchange (ICE). For short-term transactions, such as day-ahead and real time (hourly), trades are made primarily between buyers and sellers negotiating price, quantity, and point of delivery over the phone (bilateral transactions). In the Pacific Northwest, most of the price negotiations begin with prices displayed for Mid-C on the ICE trading platform.

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 1 shows the relative volume of energy in the Northwest.

Figure 1. Northwest regional forecast (Source: 2017 PNUCC)[5]

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2018, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 10,000 megawatt-hours (MWh) to over 49,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 1,600,000 MWhs. These volumes are in addition to daily broker trades and month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following market participants transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Water and Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric

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[5] pnucc.org/system-planning/northwest-regional-forecast

- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma Power

Energy traded at Mid-C is not necessarily physically generated in the Mid-Columbia River geographic area. For instance, Powerex is a merchant of BC Hydro in British Columbia and frequently buys and sells energy at Mid-C. A trade at Mid-C requires that transmission is available to deliver the energy to Mid-C. Transmission wheeling charges must be accounted for when transacting at Mid-C. Sellers at Mid-C must pay necessary transmission charges to deliver power to Mid-C, and buyers must pay necessary transmission charges to deliver power to load.

Mid-C and Idaho Power

Historically, Idaho Power wholesale energy transactions have correlated well with the Mid-C hub due to Idaho Power's proximity to the market hub and because it is the most liquid hub in the region. Energy at Mid-C can be delivered to, or received from, Idaho Power through a single transmission wheel through Avista, BPA, or PacifiCorp. Additionally, long-term monthly price quotes are readily available for Mid-C, making it an ideal basis for long-term planning.

Idaho Power uses the market to balance surplus and deficit positions between generation resources and customer demand, and to take advantage of price differences across the region. For example, when market purchases are more cost-effective than generating energy within Idaho Power's generation fleet, Idaho Power customers benefit from lower net power supply cost through purchases instead of Idaho Power fuel expense. Idaho Power customers also benefit from the sale of surplus energy. Surplus energy sales are made when Idaho Power's resources are greater than Idaho Power customer demand and when the incremental cost of these resources are below market prices. Idaho Power customers benefit from these surplus energy sales as offsets to net power supply costs through the power cost adjustment (PCA).

In 2018, Idaho Power averaged approximately 85,000 MWh of total Mid-C purchases in June and July. As stated previously, the average monthly volumes at Mid-C, on a day-ahead basis, were approximately 1,600,000 MWh. Based on these averages, Idaho Power's purchases represented about 5 percent of the total market volumes in June and July. At 5 percent of total market volume on average in June and July, Idaho Power represents a very small fraction of the Mid-C volume during the months when Idaho Power relies on Mid-C the most.

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

Modeling of the Mid-C Market in the IRP

As part of the IRP analysis, Idaho Power uses the AURORA model to derive energy prices at the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear fuel price, hydro conditions, etc. Refer to chapters 8 and 9 of the *Second Amended 2019 IRP* for more information on AURORA and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon.

Transmission wheeling rates and wheeling losses are included in the AURORA database and are part of the dispatch logic within the AURORA modeling. AURORA economically dispatches generating units, which can be located across any system in the West. All market energy purchases modeled in AURORA include these additional transmission costs and are included in all portfolios and sensitivities.

B2H Comparison to Other Resources

The *Second Amended 2019 IRP* provides an in-depth analysis of the B2H project compared to alternative resource options. Table 2 summarizes some of the high-level differences between B2H and other notable resource options.

Table 2. High-level differences between resource options

	B2H	Reciprocating engines	CCCT	Lithium batteries	1-axis solar PV
Intermittent renewable					✓
Dispatchable capacity providing	✓	✓	✓	✓	
Non-dispatchable (coincidental) capacity providing					✓
Balancing, flexibility providing	✓	✓	✓	✓	
Energy providing	✓	✓	✓	✓	✓
Variable costs (primary variable cost driver)	Mid-C market	Natural gas	Natural gas	Mid-C market	No variable costs
Capital costs	$626 per on-peak kW	$1,087-1,205 per kW/kW	$1,294/kW	$1,870-3,004 per kW	$3,329 per /on-peak kW
Fuel price risk		✓	✓		
Wholesale power market price risk	✓			✓	
Other	Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resource promotes stability in customer rates, benefit to regional grid, supports Idaho Power's clean energy goal, long-lead resource.	Scalable (modeled generators 18.8-MW nameplate), relatively short-lead resource, range driven by plant configuration.	Relatively short-lead resource, dispatchable, recent construction experience.	Uncertainty related to performance (e.g., # of lifetime cycles), dispatchable, scalable, potential for geographic dispersion, cost range driven by storage duration.	Renewable, clean, scalable (modeled plants 40-MW nameplate), diminishing on-peak contribution with expanded penetration, short-lead resource, intermittent.

Notes:

1. Provided capital costs are in nominal dollars assuming 2023 on-line date (i.e., 2023$).
2. Solar is not dispatchable but tends to produce at fairly high levels during summer periods of high customer demand. For the expressed capital cost per on-peak kW, the assumed on-peak capacity is 45 percent of installed capacity.
3. Lithium battery is a net energy consumer (roundtrip efficiency = 88 percent). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.
4. B2H capital-cost estimate includes a 20-percent contingency. No other resources include contingency. B2H and solar capital costs are expressed in terms of $/on-peak kW, where on-peak kW for B2H are based on 500-MW summer capacity and for solar is based on on-peak capacity equal to 45 percent of installed capacity.

Idaho Power's Transmission System

Idaho Power's transmission system is a key element to providing reliable, responsible, fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 6.1

of the *Second Amended 2019 IRP* and in Figure 2. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances, the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Columbia River, wind in Wyoming, solar in the desert southwest).
For much of its history, Idaho Power has taken advantage of resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power fully utilizes the capacity of these lines. Additional transmission capacity is required to access resources to serve incremental increases in peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

Transmission lines are constructed and operated at different operating voltages depending on purpose, location, and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV, but these voltages will not be discussed further in this appendix; the focus of this appendix is on higher voltage transmission lines used for moving bulk electricity. The higher the voltage, the greater the capacity of the line, but also greater construction cost and physical size requirements.

The utility industry often compares transmission lines to roads and highways. Typically, lower-voltage transmission lines (138 kV) are used to facilitate delivery of energy to substations to serve load, like a two-lane highway, while high-voltage transmission lines are used for bulk transfer of energy from one region to another, like an interstate highway. Much like roads and highways, transmission lines can become congested. Depending on the capacity needs, economics, distance (higher voltages result in less losses over long distances), and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines are chosen.

Transmission Capacity Between Idaho Power and the Pacific Northwest

A transmission path is one or more transmission lines that collectively transmit power to/from one geographic area to another. Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW are on the Idaho to Northwest path (Western Electricity Coordinating Council [WECC] Path 14), and 80 MW are on the Montana–Idaho path (WECC Path 18).
The Idaho to Northwest transmission path is comprised of three 230-kV lines, one 500-kV line, and one 115-kV line. The capacity limit on the path is established through a WECC rating process based on equipment overload ratings resulting from the loss of the most critical element on the transmission system. Collectively, these lines between Idaho and the Northwest have a transfer capacity rating that is greater than the individual rating of each line but less than the sum

of the individual capacity ratings of each line. Figure 2 shows an overview of Idaho Power's high-voltage transmission system.

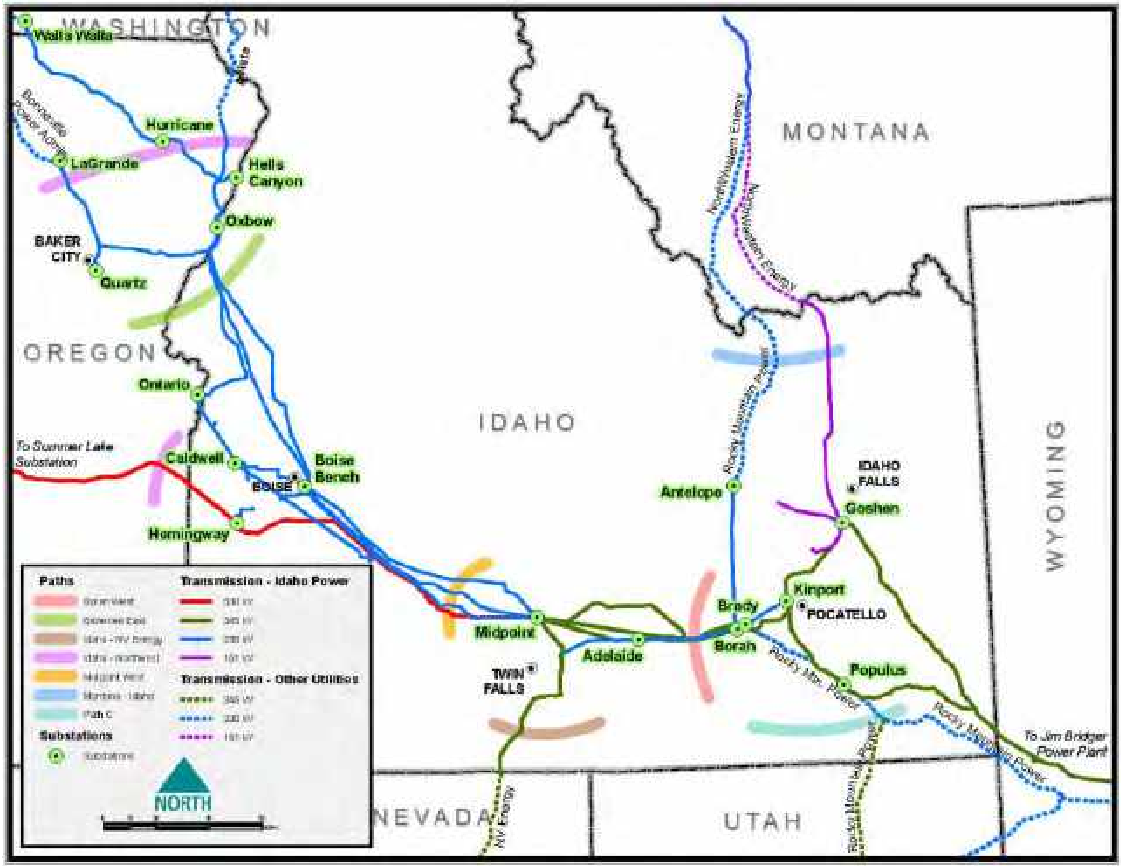

Figure 2. Idaho Power transmission system map

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2019. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load. Although Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest and Idaho Power's system, after all other uses are accounted for, Idaho Power will only able to use 304 MW to serve Idaho Power's native load in 2019. Idaho Power used 366 MW to serve BPA or PacifiCorp network load on Idaho Power's system, 280 MW were allocated to Transmission Reserve Margin (TRM), and 330 MW were allocated to Capacity Benefit Margin (CBM).

Table 3. Pacific Northwest to Idaho Power import transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	365
Boardman Generation	60
Fighting Creek (PURPA)	4
Pallette Load (PacifiCorp—Network Customer)	1
TRM	280
CBM	330
Subtotal	**1,040**
Pacific Northwest Purchase (Idaho Power Load Service)	240
Total	**1,280**

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability to ensure a safe and reliable transmission system. Idaho Power's TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loopflow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. However, physics dictate the actual power flow over the path (based on the path of least resistance), so actual flows don't equal contract-path schedules. The difference between scheduled and actual flow is referred to as unscheduled flow or loopflow. The average adverse loopflow across the Idaho to Northwest path during the month of July is 280 MW.

CBM is transmission capacity Idaho Power sets aside, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions. Idaho Power includes the 330 MW of CBM toward meeting a 15 percent planning margin.

Montana–Idaho Path Utilization

To utilize Idaho Power's share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 2 above.

Idaho to Northwest Path Utilization

To utilize Idaho Power's share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Table 4 details a typical summer allocation of the Idaho to Northwest capacity:

Table 4. The Idaho to Northwest Path (WECC Path 14) summer allocation

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

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

Avista, BPA and PacifiCorp share an allocation of capacity on the western side of the Idaho to Northwest path, and Idaho Power owns 100 percent of the capacity on the eastern side of the Idaho to Northwest path. For Idaho Power to transact across the path and serve customer load, Idaho Power's Load Servicing Operations must purchase transmission service from Avista, BPA, or PacifiCorp to connect the selling entity, via a contract transmission path, to Idaho Power.

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 500 MW in the summer months (April–September), and 200 MW in the winter months (January–March and October–December). A total breakdown of capacity rights of the B2H permitting coparticipants can be found in the Project Coparticipants section of this report. The Idaho to Northwest path is identified in Figure 2 above.

Regional Planning—Studies and Conclusions

Idaho Power is currently a member of the NorthernGrid regional planning organization after joining in early 2020. NorthernGrid operates in compliance with FERC orders 890 and 1000.

Prior to joining NorthernGrid, Idaho Power was a member of and participated in the Northern Tier Transmission Group (NTTG) regional planning organization. The purpose of regional planning is to consolidate each member's local transmission plans and determine a regional plan that can meet the needs of the combined member footprint in a more efficient or cost-effective manner.

At NTTG, all member utilities submitted their load forecasts, generation forecasts, and transmission needs. NTTG studied the members' transmission footprints to determine the more efficient or cost-effective plan to meet those needs.

B2H was an integral part of NTTG's 10-year plan and in the 2018–2019 planning cycle, B2H was selected into the NTTG's Regional Transmission Plan. NTTG's analysis indicated B2H is the most cost-effective and efficient project to meet the needs of the NTTG footprint. The study noted that "Boardman to Hemingway resolved performance issues between the Northwest and Idaho under summer import conditions."[6]

For the most recent updates related to Idaho Power's regional planning organization, refer to the NorthernGrid website at northerngrid.net.

[6] NTTG 2018–2019 Regional Transmission Plan. nttg.biz

THE B2H PROJECT

Project History

The B2H project originated from Idaho Power's 2006 IRP. The 2006 IRP specified 285 MW of additional transmission capacity, increasing Idaho Power's connection to the Pacific Northwest power markets, as a resource in the preferred resource portfolio. A project had not been fully vetted at that time but was described as a 230-kV transmission line between McNary Substation and Boise. After the initial identification in the 2006 IRP, Idaho Power evaluated numerous capacity upgrade alternatives. Considering distance, cost, capacity, losses, and substation termination operating voltages, Idaho Power determined a new 500-kV transmission line between the Boardman, Oregon, area and the proposed Hemingway 500-kV substation would be the most cost-effective method of increasing capacity. Refer to Appendix D-1 for more information on the upgrade options considered.

Transmission capacity, especially at 500 kV, can be described as "lumpy" because capacity increments are relatively large between the different transmission operating voltages. In the 2009 IRP, Idaho Power assumed 425 MW of capacity, which was 50 percent of the assumed total rating. Idaho Power's long-standing preference was to find a partner or partners to construct B2H with to take advantage of economies of scale. In the 2011 IRP, Idaho Power assumed 450 MW of capacity. In 2012, Idaho Power achieved two major milestones: 1) PacifiCorp and BPA officially joined the B2H project as permitting coparticipants and 2) Idaho Power received a formal capacity rating for the B2H project via the WECC Path Rating Process (more on this process in preceding section). In the 2013 IRP, Idaho Power began to use the negotiated capacity from the permitting agreement: 500 MW in the summer and 200 MW in the winter, a yearly average of 350 MW, for a cost allocation of 21 percent of the total project. Idaho Power used the same 21.2 percent interest in the 2015, 2017 and 2019 IRPs.

Public Participation

The B2H project development has involved considerable stakeholder interaction over the last 12 years. Idaho Power has hosted and participated in over 275 public and stakeholder meetings with an estimated 4,500+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.

4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings. Additionally, numerous meetings with individuals and advocacy groups were held during and after the process.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report[7], and Idaho Power's initial scoping activities, visit the documents section[8] on the B2H website.

Throughout the BLM's NEPA process, including development of the Draft Environmental Impact Statement (EIS), issued Dec. 19, 2014, and prior to the Final EIS, issued Nov. 22, 2016, Idaho Power worked with landowners, stakeholders and jurisdictional leaders on route refinements and to balance environmental impacts with impacts to farmers and ranchers. For example, Idaho Power met with the original "Stop Idaho Power" group in Malheur County to help the group effectively comment and seek change from the BLM when the Draft EIS indicated a preference for a route across Stop Idaho Power stakeholder lands. BLM's decision was modified, and the route moved away from an area of highly valued agricultural lands in the Final EIS almost two years later.

Idaho Power worked with landowners in the Baker Valley, near the National Historic Oregon Trail Interpretive Center (NHOTIC), to move an alternative route along fence lines to minimize impacts to irrigated farmland, where practicable. This change was submitted by the landowners and included in the BLM's Final EIS and ROD (issued Nov. 17, 2017). Another change in Baker County was in the Burnt River Canyon and Durkee area, where Idaho Power worked with the BLM and affected landowners to find a more suitable route than what was initially preferred in the Draft EIS. Idaho Power is still working with landowners and local jurisdictional leaders to microsite in these areas to minimize impacts.

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize

[7] boardmantohemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf

[8] boardmantohemingway.com/documents.aspx

visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

However, Idaho Power worked with Umatilla County, local jurisdictional leaders and landowners to identify a new route through the entire county, essentially moving the line further south and away from residences, ranches, and certain agriculture. This southern route variation through Umatilla County was included the BLM's Agency Preferred route.

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all the noted parties in the local area. A major milestone was achieved when the U.S. Navy issued a Record of Decision for the proposed route in September 2019.

Finally, in Union County Idaho Power worked with local jurisdictional leaders, stakeholder groups, such as the Glass Hill Coalition and some members of StopB2H (prior to that group's formation) to identify new route opportunities. The Union County B2H Advisory Commission agreed to submit a route proposal to the BLM that followed existing high-voltage transmission lines, which was later identified as the Mill Creek Alternative. At the same time, Idaho Power met with a large landowner to adjust the Morgan Lake Alternative route to minimize impacts. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (referred to as the Glass Hill Alternative) by local landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its Application for Site Certificate filed with the Oregon Department of Energy in September 2018. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Mill Creek alternatives. As of the date of the filing of the *Second Amended 2019 IRP*, Idaho Power understands that the Morgan Lake route alternative is preferred by the local community.

Project Activities

Below is a summary of notable activities by year since project inception. For more information about any of the activities, please visit the B2H website.

2006

Idaho Power files its IRP with a transmission line to the Pacific Northwest identified in the preferred resource portfolio.

2007

Idaho Power analyzes the capacity and cost of different transmission line operating voltages and determines a new 500-kV transmission line to be the most cost-effective option to increase capacity and meet customer needs. Idaho Power files a Preliminary Draft Application for Transportation and Utility Systems and Facilities on Federal Lands. Idaho Power scopes routes.

2008

Idaho Power submits application materials to the BLM. Idaho Power submits a Notice of Intent to the EFSC. The BLM issues a Notice of Intent to prepare an EIS; officially initiating the BLM-led federal NEPA process. Idaho Power embarks on a more extensive public outreach program to determine the transmission line route.

2009

Idaho Power pauses NEPA and EFSC activities to work with community members throughout the route as part of the CAP to identify a proposed route that would be acceptable to both Idaho Power and the public. Forty-nine routes and/or route segments were considered through CAP.

2010

The CAP concludes. Idaho Power resubmits a proposed route to the BLM based on input from the CAP. The BLM re-initiates the NEPA scoping process and solicits public comments. Idaho Power publishes its B2H Siting Study. Idaho Power files a Notice of Intent with EFSC.

2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects[9].

2012

The ODOE conducts informational meetings and solicits comments. The ODOE issues a Project Order outlining the issues and regulations Idaho Power must address in its Application for Site Certificate. Additional public outreach and analysis resulted in route modifications and refinements submitted to the BLM. Idaho Power issues a Siting Study Supplement. Idaho Power conducts field surveys for the EFSC application. WECC adopts a new Adjacent Transmission Circuits definition with a separation distance of 250 feet, which would later modify routes in the EIS process. Idaho Power receives a formal capacity rating from WECC.

[9] boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf

2013

Public meetings are held. Idaho Power submits its Preliminary Application for Site Certificate to the ODOE. The BLM releases preliminary preferred route alternatives and works on a Draft EIS.

2014

The BLM issues a Draft EIS identifying an Agency Preferred Alternative. The 90-day comment period opens. Idaho Power conducts field surveys for EFSC application.

2015

The BLM hosts open houses for the public to learn about the Draft EIS, route alternatives, environmental analysis. The BLM reviews public comments. Idaho Power notifies the BLM of a preferred termination location, Longhorn Substation. Idaho Power submits an application to the Navy for an easement on the Naval Weapons System Training Facility in Boardman.
Idaho Power conducts field surveys for the EFSC application.

2016

Idaho Power submits a Draft Amended Application for Site Certificate to the ODOE for review. The BLM issues a Final EIS identifying an environmentally preferred route alternative and an Agency Preferred route alternative. Idaho Power incorporates the Agency Preferred route alternative into the EFSC application material. Idaho Power collaborates with local area stakeholders in Morrow County to find a routing solution on Navy-owned land. Idaho Power submits a revised application to the Navy. Idaho Power conducts field surveys for the EFSC application.

2017

Idaho Power submits an Amended Application for Site Certificate to the ODOE. The BLM issues a Record of Decision.

2018

ODOE and Idaho Power conduct public meetings after ODOE determined the Application for Site Certificate was complete. The Oregon PUC issues Order No. 18-176 in Docket No. LC 68 specifically acknowledging Idaho Power’s 2017 Integrated Resource Plan and action items related to B2H. The U.S. Forest Service issues a Record of Decision. Idaho Power prepares and submits a Geotechnical Plan of Development to the BLM for approval.

2019

The U.S. Forest Service issues ROW easement. ODOE issues a Draft Proposed Order (DPO). The U.S. Navy issues a Record of Decision. BPA issues a ROD for moving the existing 69-kV line from Navy property to accommodate the B2H project. Idaho Power coordinates with BLM on Geotechnical Plan of Development. Preparations begin for issuing detailed design bid package.

2020

The U.S. Navy issues an easement for the B2H project. Based on the DPO, ODOE issues a Proposed Order and notice for Contested Case. Preparations begin for several pre-construction activities; which include completing LIDAR (aerial mapping) for the entire B2H project route and initiating detailed design. Additionally, Idaho Power is initiating the following activities for 2021: ROW acquisition, legal surveys, and geotechnical investigation.

For a detailed list of project activities by year, please refer to Appendix D-2.

Route History

As stated previously, the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500-kV line between the Boardman area and the Hemingway Substation. Several northern terminus substations were considered over the years, including the Boardman coal plant 500-kV yard, the proposed Grassland Substation to be constructed by Portland General Electric to integrate the then-proposed Carty Plant, and the proposed Longhorn Substation, which at the time was proposed by BPA to integrate wind onto the BPA 500-kV transmission system. During scoping, a considerable number of routes were considered to connect Hemingway and the Boardman area. Figure 3 is a snapshot of a number of routes considered early on during the CAP process (2009 timeframe). Numerous alternatives were considered, including routes through Idaho and through central Oregon. This large number of routes was further refined during the CAP process.

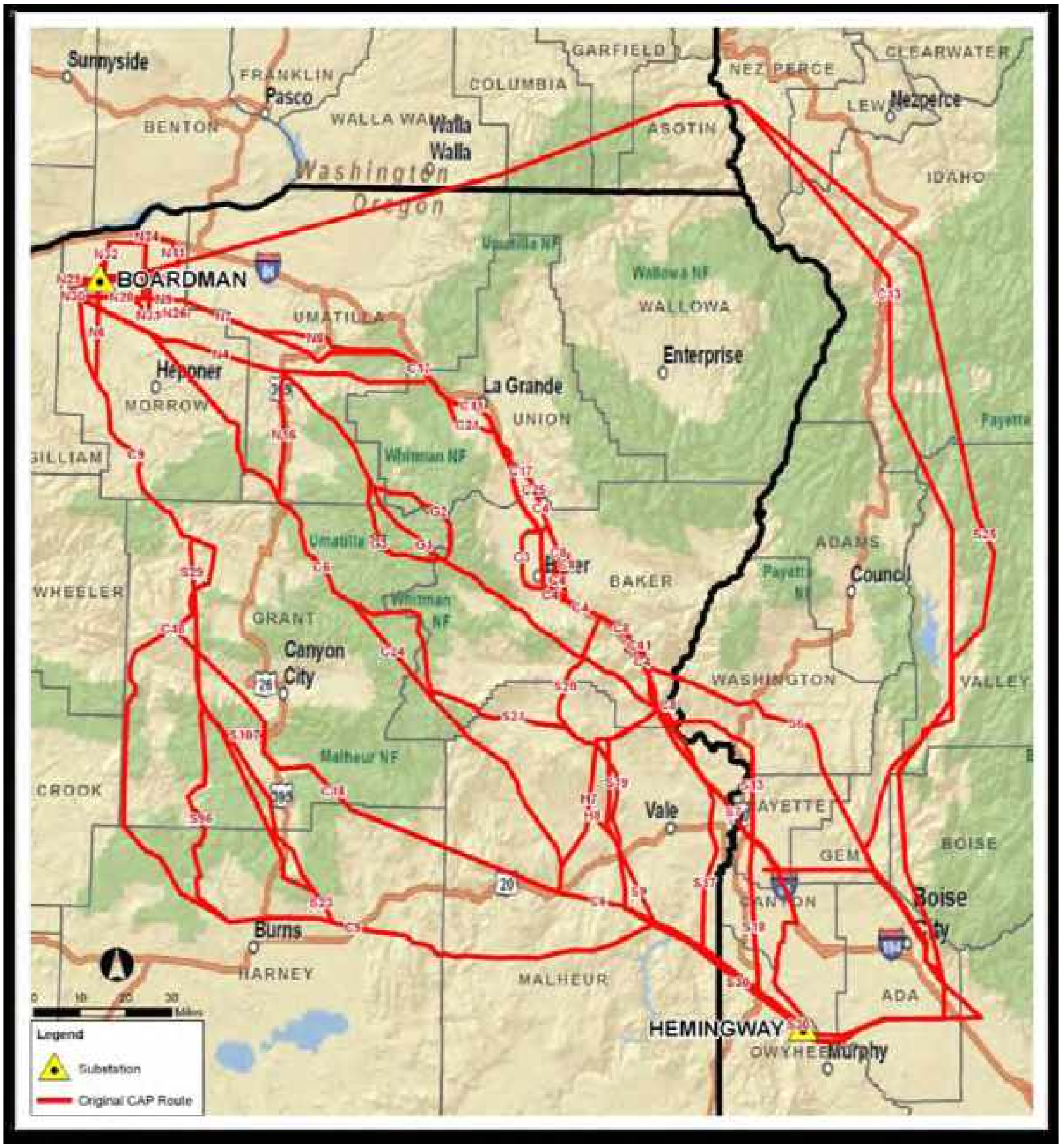

Figure 3. Routes developed by the Community Advisory Process teams (2009 timeframe)

The CAP process resulted in Idaho Power submitting the route shown in Figure 4 as the company's proposed route in the BLM-led NEPA process.

Figure 4. **B2H proposed route resulting from the Community Advisory Process (2010 timeframe)**

The BLM considered Idaho Power's proposed route, along with a number of other reasonable alternative routes, in the NEPA process. Figure 5 shows the route alternatives and variations considered in the BLM's November 2016 Final EIS.

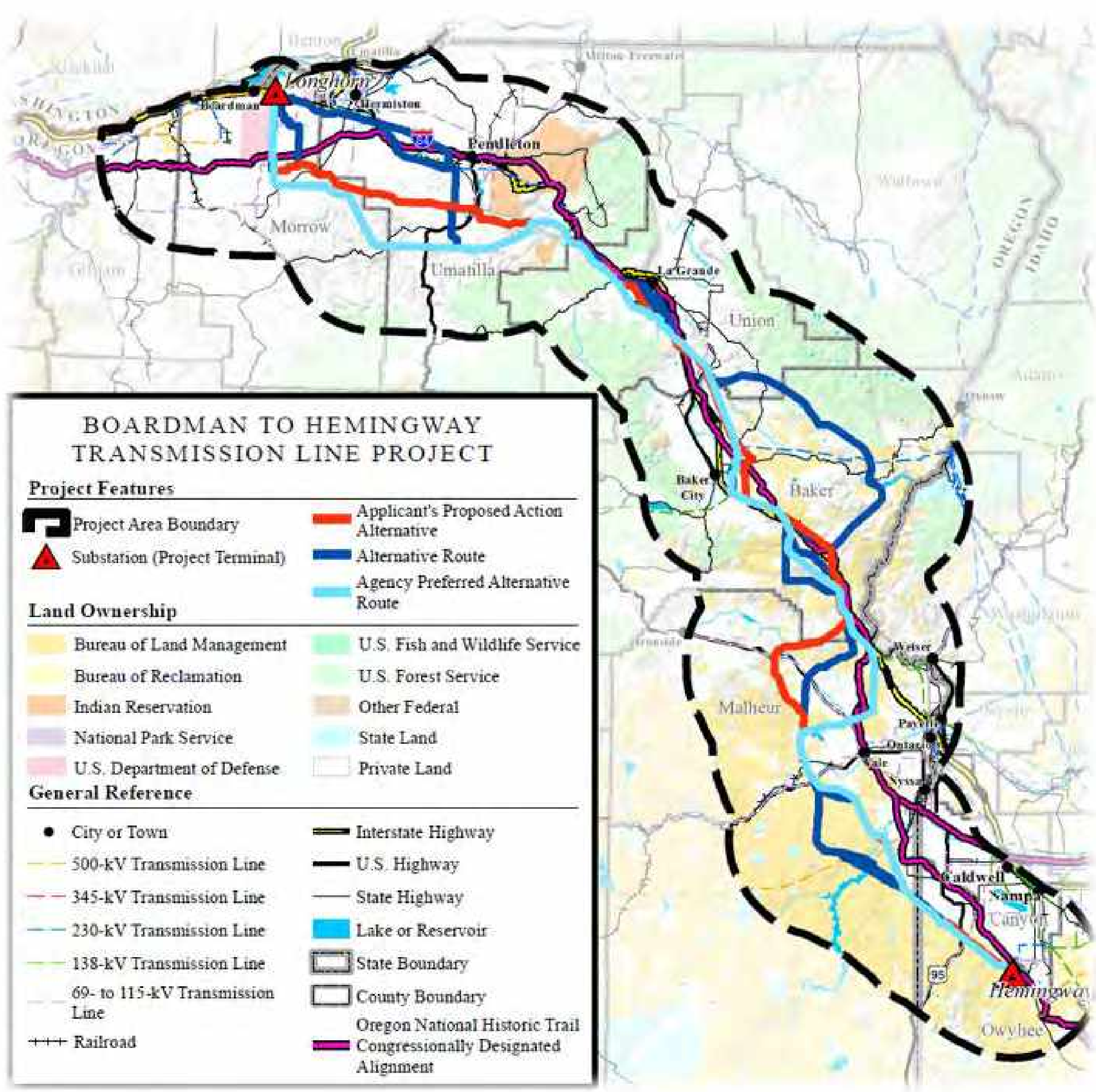

Figure 5. BLM final EIS routes

The conclusion of the BLM-led NEPA process, the BLM's ROD, resulted in a singular route—the BLM's Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the U.S. Forest Service [USFS], the Bureau of Reclamation, and the U.S. Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure 6 shows the BLM's Agency Preferred route.

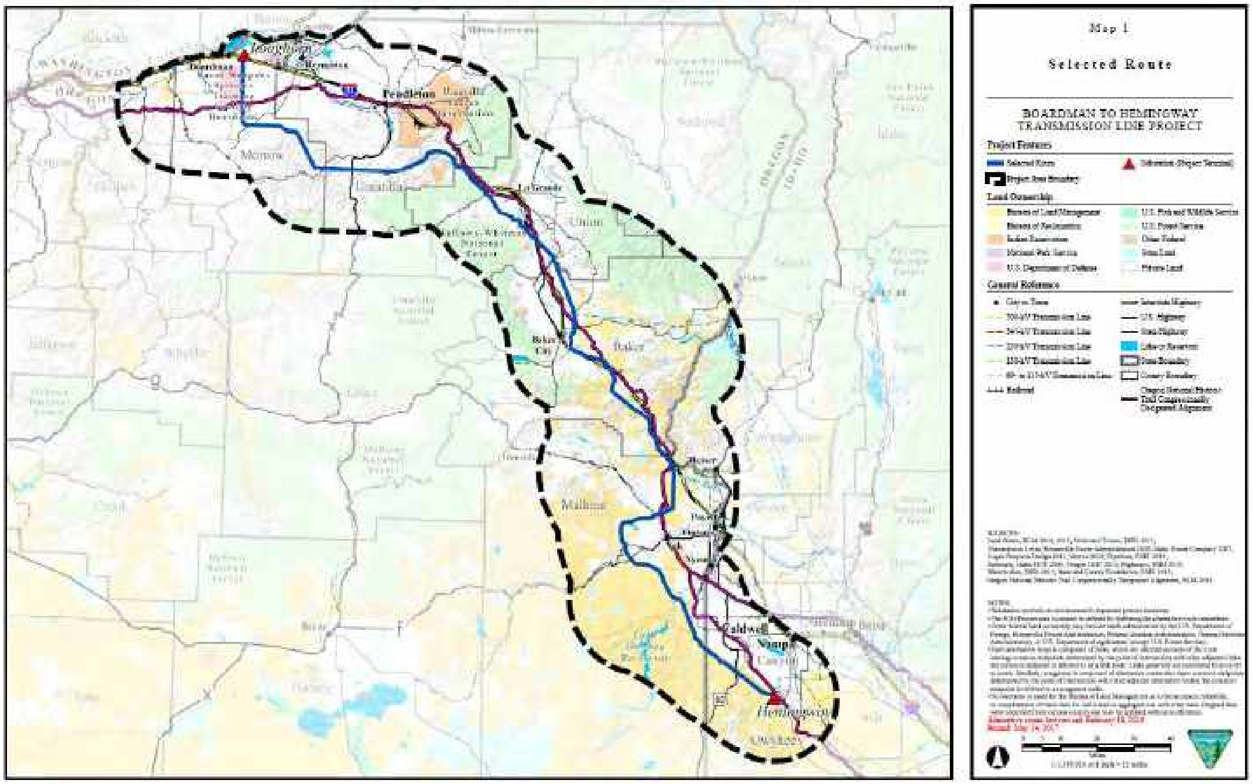

Figure 6. BLM Agency Preferred route from the 2017 BLM ROD

As discussed previously, the BLM-led NEPA process and the EFSC process are separate and distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM's Agency Preferred route, except for a small section of private property west of La Grande. The BLM's Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders in the area. The section the BLM chose was not the county's stated preference, nor was it the variation Idaho Power had worked with a large local landowner to modify to minimize impacts to his property.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the county's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power continues to work with the community to finalize which of the two variations in this area will be constructed. Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

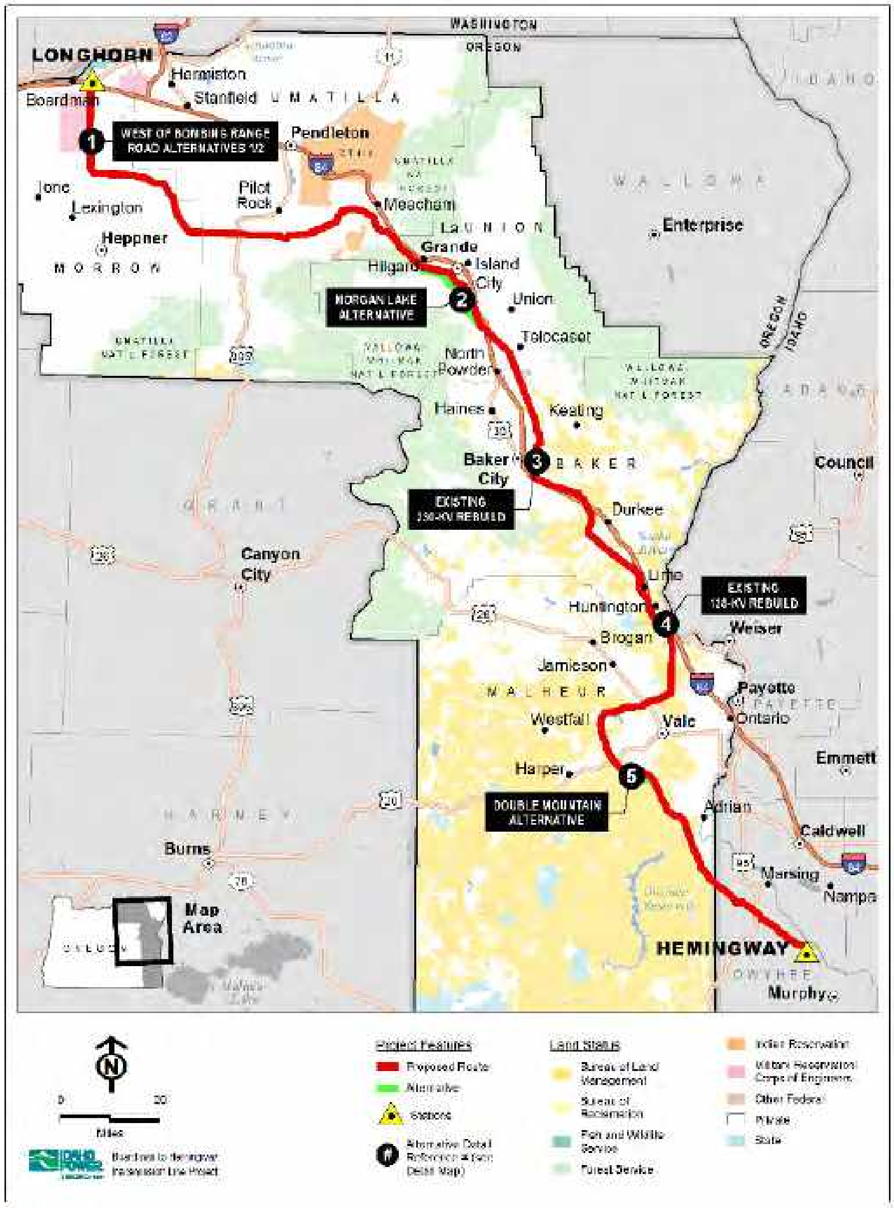

Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate

B2H Capacity Interest

Per the terms of the Joint Permit Funding Agreement, each coparticipant (funder) is assigned a permitting interest based on the annual weighted capacity expressed in the project. The permitting interest is determined by the sum of a funder's eastbound capacity interest and westbound capacity interest, divided by the total of all eastbound and westbound capacity interest. Table 5 details the capacity interest of each funder.

Table 5. B2H joint permit funding capacity interests by funder

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
Idaho Power	350 MW (Average) 500 MW (Summer) 200 MW (Winter)	0 MW	21.2%
PacifiCorp	300 MW	600 MW	54.5%
BPA	400 MW (Average) 250 MW (Summer) 550 MW (Winter)	0 MW	24.2%
Unallocated	0 MW	400 MW	

Idaho Power's capacity interest is seasonally shaped, with 500 MW of eastbound capacity from April through September and 200 MW of eastbound capacity from January through March and October through December. BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity from April through September and 550 MW of eastbound capacity from January through March and October through December. PacifiCorp's capacity is constant throughout the year. The sum of the capacity interest in the east-to-west direction is less than the rating (1,000 MW), so the unallocated capacity is divided among the funders based on their respective percentage permitting interest.

The seasonal capacity shaping is a great benefit for Idaho Power's customers, and one of the reasons why the B2H project is such a competitive and cost-effective option in the IRP process. Idaho Power is effectively purchasing 500 MW of capacity (peak summer need) at a cost based on 350 MW of capacity.

Capacity Rating—WECC Rating Process

Idaho Power coordinated with other utilities in the Western Interconnection via a peer-reviewed process known as the WECC Path Rating Process. Through the WECC Path Rating Process, Idaho Power worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation on the bulk power system. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

B2H Design

B2H is routed and designed to withstand catastrophic events, including, but not limited to, the following:

- Lightning
- Earthquake
- Fire
- Wind/tornado
- Ice
- Landslide
- Flood
- Direct physical attack

The following sections provide more information about the design of the B2H transmission line and address each of the catastrophic events listed above.

Transmission Line Design

The details below are not inclusive of every design aspect of the transmission line but provide a brief overview of the design criteria. The B2H project will be designed and constructed to meet or exceed all required safety and reliability criteria.

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lighting from striking conductors. See Figure 8 for a cross-section of a transmission line.

For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its conductive properties, and it provides the ability to move more power using a smaller amount of material.

Shield wires, typically either steel or aluminum, and occasionally including fiber optic cables inside for communication between substation equipment, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures, which provide an economical means to support large conductors for long spans over long distances. The typical structure height for B2H is 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,200 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (less structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

Foundations are the support mechanism that bind the structures to the earth and safely keep the phase conductors and shield wires in the air. For the B2H project, the foundations at each lattice tower structure are planned to be concrete-drilled pier shafts. A cylindrical hole will be drilled at each tower footing of adequate diameter and depth to support the loads applied to the structure from the shield wires and phase conductors. The loads applied to structures via shield wires and conductors are discussed in further detail below.

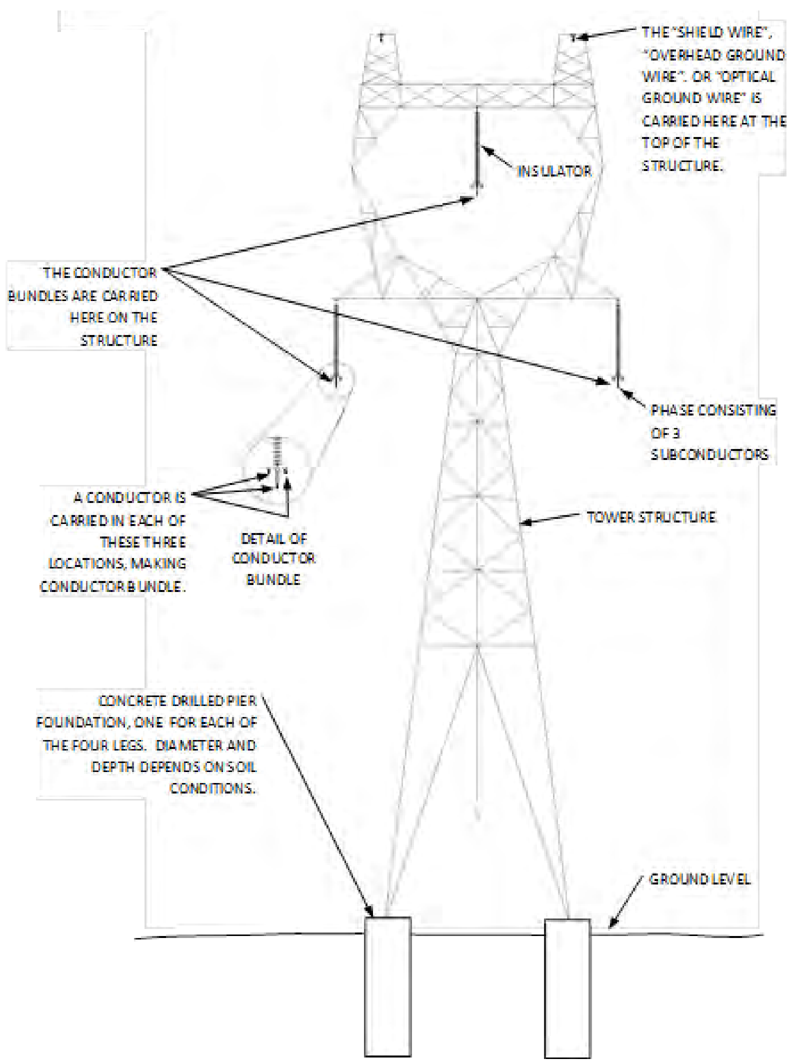

Figure 8. Transmission tower components

Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's EFSC application includes an exhaustive list of standards. Several notable standards are as follows:

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*
- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the provisions in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

Transmission Line Foundation Design

The 500-kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be concrete pier foundations designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake motion; historically, transmission structures have performed well under earthquake events,[10, 11] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[12] This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these

[10] Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192 © ASCE 2013.

[11] Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

[12] USDA RUS Bulletin 1751-801.

forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. When compared to other resource alternatives, B2H may be more resilient to smoke. For instance, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

Wind Gusts/Tornados

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

Ice

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

Landslide

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section above. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

Flood

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

Direct Physical Attack

A direct physical attack on the B2H transmission line will remove the line's ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H's ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

B2H Design Conclusions

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

PROJECT COPARTICIPANTS

PacifiCorp and BPA Needs

PacifiCorp and BPA are coparticipants in the permitting of the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H project indicates the regional significance of the project and the value the project brings to customers throughout the West. More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

PacifiCorp

PacifiCorp is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp is a leading western US energy services provider and the largest single owner of transmission in the West, serving 1.9 million retail customers in six western states. PacifiCorp is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit pacificorp.com for more information.

The existing transmission path between the Pacific Northwest and Intermountain West regions is fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its share of the bidirectional capacity of B2H to increase reliability and to enable more efficient use of existing and future resources for its customers. PacifiCorp has identified the following list of additional benefits:

- **Customers:** PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.

- **Renewables:** PacifiCorp has identified B2H as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states.

- **Regional Benefit:** PacifiCorp, as a member of the regional planning entity NTTG (now NorthernGrid as of early 2020), supports the inclusion of B2H in the NTTG regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs.

- **Balancing Area Operating Efficiencies:** PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

- **Regional Resource Adequacy:** PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.

- **Grid Reliability and Resiliency:** The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.

- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation:** New legislation and rules for recently passed legislation are being developed to meet state specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.

- **EIM:** PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.

BPA

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 27 percent of the electric power used in the Pacific Northwest. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

BPA identified the B2H project plus associated asset exchange as a priority for pursuit for delivering power to serve the load of its customers in southeast Idaho. BPA's load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA's winter peak load couples well with Idaho Power's summer peak load allowing for seasonal shaping of the allocation of B2H capacity, which increases the cost-effectiveness of the project. For more information about the southeast Idaho load service analysis, visit bpa.gov.[13]

As a federal agency, BPA has responsibilities to comply with NEPA and other legal requirements prior to making a final decision or taking any final agency action, such as participating in transmission line construction or committing to enter into contracts associated with the B2H project. To that end, BPA will conduct any necessary reviews following completion of the ongoing coparticipant negotiations as appropriate.

Coparticipant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012. The agreement was amended on February 13, 2018. The Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands.

Related to the project, but not specific to the B2H permitting activities, the B2H coparticipants entered into an MOU on January 12, 2012, to accomplish the following: 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the coparticipants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project.

The funders are currently engaged in negotiations regarding potential agreements for the construction and ownership of the project.

[13] Southeast Idaho Load Service analysis: bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

Coparticipant Expenses Paid to Date

Approximately $110 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through June 30, 2020. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $74 million of that amount as reimbursement from the project coparticipants as of June 30, 2020. Coparticipants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

COST

Cost Estimate

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unanticipated expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million. Notable items that increased the cost relative to the 2017 IRP cost estimate include: increased steel and aluminum estimates, increased labor cost estimates, increased Longhorn substation estimate, and increased AFUDC.

Transmission Line Estimate

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500-kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

Substation Estimates

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation and must complete all NEPA reviews and other legal requirements before making a final decision to construct Longhorn Substation. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

Calibration of Cost Estimates

The B2H estimate was reviewed and approved by BPA and PacifiCorp. BPA and PacifiCorp both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500-kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500-kV line (39 miles, in-service 2016)
- PacifiCorp: Sigurd to Red Butte 345-kV line (160 miles, in-service 2015)
- PacifiCorp: Mona to Oquirrh 500-kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

Costs Incurred to Date

Approximately $110 million, including AFUDC, has been expended on the B2H project through June 30, 2020. The $110 million incurred through June 30, 2020, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses.

Transmission Revenue

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. However, historically, additional transmission wheeling revenue has not been quantified for transmission capacity additions. Starting with the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native-load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system.

Idaho Power's FERC transmission rate is calculated as follows:

$$Transmission\ Rate = \frac{Transmission\ Costs\ (\$)}{Transmission\ Usage\ (MW * year)}$$

Per the formula above, since transmission costs will likely go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission wheeling customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed a constant transmission usage by third parties (no increase or decrease) from 2018 levels.

BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect, and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the Resource Need section.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power (2,050 MW total bi-directionally). Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

Clean Energy Future

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. Experts, in-depth studies, and even the American

Wind Energy Association, cite the need for an expanded and robust transmission system in a decarbonized future[14].

Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources)

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized transmission allowed them to build and share larger, more cost-effective and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 6 illustrates peak-load estimates, by utility and season, for 2028. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 68,000 MW. When all regions plan together, the total generating capacity can be reduced to 64,100 MW, a nearly 6 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

Table 6. 2028 peak load estimates—illustration of load diversity between western regions

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	8,400	10,600	10,600
British Columbia	9,700	13,100	13,100
Chelan	300	600	600
Grant	1,200	1,100	1,100
Idaho Power	4,400	3,500	4,400
Nevada	7,600	6,300	7,600
Northwestern Energy	2,000	1,900	2,000
PacifiCorp—East	10,400	8,900	10,400
PacifiCorp—West	3,800	4,000	4,000
Portland General	3,900	3,800	3,900
Puget Sound	3,800	5,300	5,300

[14] awea.org/Awea/media/Policy-and-Issues/Electricity/Transmission-Fact-Sheet.pdf
utilitydive.com/news/as-operators-update-grid-planning-for-renewables-transmission-remains-key/505065/
pv-magazine-usa.com/2019/08/30/clean-energy-groups-allies-call-for-overhaul-of-the-transmission-grid/

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Seattle City	1,300	1,600	1,600
Tacoma	600	1,000	1,000
Total	**59,600**	**64,100**	**68,000**

Note: From EEI Load Data used for the WECC 2028 ADS PCM

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than in the winter or even late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring/early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. In contrast, additional transmission capacity may enable utilities to leverage their transmission system to access generation capacity already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the *Second Amended 2019 IRP*, the portfolios that are the most cost-effective, other than B2H portfolios, include new natural gas generation. In this case, B2H provides an alternative to building carbon-emitting supply-side resources.

Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching higher cost, less efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction becomes constrained and power prices in Idaho and to the east will generally be high, while power prices in the Pacific Northwest will be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region.
The construction of B2H will help alleviate this constraint and create a win–win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a lower cost. The reverse situation is true as well—the Pacific Northwest will benefit from economical resources from the Mountain West region during certain times of the year.

Renewable Integration

To facilitate a transition from coal and fossil fuel resources to meet Idaho Power and surrounding state clean energy goals, the region requires new and upgraded transmission capacity to integrate and balance intermittent resources like wind and solar. Existing renewable generation is, at times, curtailed due to a lack of transmission capacity to move the energy to load. B2H can facilitate the transfer of geographically diverse renewable resources across the western grid and help ensure our clean energy grid of the future is robust and reliable.

Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500-kV transmission lines, such as B2H, substantially increase the grid's ability to recover from unexpected disturbances. Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500-kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.

2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect

Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

Resource Reliability

The forced outage rate of transmission lines has historically been a fraction of traditional generation resources. Availability and contribution to resource adequacy on the power grid, vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. Outage statistics between transmission and generation differ, as transmission varies in voltage class and total line length, while generators mostly differ in total size and fuel type. A telling sign of the reliability of a generation resource is the equivalent forced outage rate when needed (under demand) (EFORd). The EFORd is calculated based on the amount of time a generator is either de-rated, or completely forced out of service, while needed. De-rating a generator would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an unexpected forced outage rate of 0.4 percent (line miles/100 miles x SCOF x MTTR). Stated differently, the B2H transmission line is expected to have 99.6 percent availability when needed.

Table 7. NERC—AC transmission circuit sustained outage metrics

Voltage Class	Circuit Miles	No. of Circuits	No. of Outages	Total Outage Time (hr)	Frequency (SCOF) (per 100 circuit miles per yr)	Frequency (SOF) (per circuit per yr)	MTTR or Mean Outage Duration (hr)
200–299 kV	103,558	4,477.5	876	14,789.6	0.8459	0.1956	16.9
300–399 kV	56,791	1,623.6	394	19,766.8	0.6938	0.2427	50.2
400–599 kV	32,184	594.7	141	3,957.9	0.4381	0.2371	28.1
600–799 kV	9,451	110.0	28	342.4	0.2963	0.2545	12.2
All Voltages	201,985	6,805.8	1,439	38,856.7	0.7124	0.2114	27.0

By comparison, Table 8, lists the average EFORd for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFORd for gas power plants.

Table 8. NERC forced-outage rate information for a fossil or gas power plant

Generation Type	Unit Size	EFORd
Fossil (general)	All Sizes	7.96%
Fossil (general)	100–199 MW	7.49%
Fossil (general)	200–299 MW	5.85%
Gas	All Sizes	9.61%
Gas	1–99 MW	9.72%
Gas	100–199 MW	6.85%

A transmission line with a forced outage rate of less than 1 percent is significantly more reliable than a power plant, which has an EFORd of 7 to 10 percent. Of course, a transmission line requires generating resources to provide energy to the line to serve load. However, energy sold as "Firm" must be backed up and delivered even if a source generator fails. Therefore, Firm energy purchases would have an EFORd consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$Electrical\ Losses = Current^2 \times Resistance$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

Flexibility

Advances in technology are pushing certain existing generation resources toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the West, and for Pacific Northwest utilities to purchase energy from southern and eastern markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits, and the expansion of this transmission system (i.e., B2H) facilitates the realization of these benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. Additional Northwest utilities are joining the EIM increasing the value the transmission system provides. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that EIM participation does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

B2H Complements All Resource Types

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[15] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent[16]. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise installation would generate over 25 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

B2H Benefits to Oregon

Economic and Tax Benefits

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit of the line is shown in Table 9 below, excluding BPA's 24 percent project interest. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

Table 9. Projected annual B2H tax expenditures by county*

Oregon County	Property Tax (excluding BPA's potential 24% interest)
Morrow	$386,498
Umatilla	$251,957
Union	$947,594
Baker	$1,868,433
Malheur	$1,879,992
Total Oregon Tax Benefit	**$5,334,474**

***The property tax valuation process for utilities is determined differently than locally assessed commercial and residential property. The Oregon Department of Revenue determines the property tax value for Idaho Power Company's ("Idaho Power" or "Company") property (transmission, distribution, production, etc.) as one lump sum value (i.e., not by individual assets). The Oregon Department of Revenue then apportions and remits Idaho Power's lump sum assessed value to each county. It is from those values that the county generates property tax bills for the Company. Idaho Power converts its Oregon property tax payment by county into an

[15] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is nearly 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, Annual Technology Baseline: Electricity: 2019).

[16] NREL, System Advisory Model

internal rate that can be applied to Idaho Power's transmission, distribution, and production book investment to estimate taxes. This internally calculated tax rate is what was applied to the Boardman to Hemingway ("B2H") estimated book investment (project cost) to estimate property taxes. The table above summarizes the tax value derivation. For estimation purposes, the estimated property taxes are assumed at Idaho Power tax rates. PacifiCorp property taxes may differ from Idaho Power's property taxes. It is Idaho Power's understanding that BPA, as a federal agency, would not be obligated to pay taxes on its potential ownership interest. Therefore, the total estimated tax amount is discounted by BPA's 24 percent potential ownership interest.

Local Area Electrical Benefits

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully used for existing customer commitments. Idaho Power currently serves customers in Owyhee County, Idaho, and Malheur County and portions of Baker County in Oregon. PacifiCorp, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's network transmission rate to receive transmission service from the BPA system. While BPA continues to refine its financial analysis, its initial modeling indicates that a share of the B2H project with asset exchange may be a cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and, as discussed previously, B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230-kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the *Second Amended 2019 IRP*, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power' resource needs.

Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power's share of the B2H project is $292 million, including Idaho Power's AFUDC. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

The B2H project has considerable capital-cost bandwidth. Idaho Power notes that the B2H capital cost includes a 20 percent cost contingency, which is not included for other resource options considered. Based on net present value (NPV) analysis over the 20-year planning horizon, Idaho Power's cost share of the B2H project could increase substantially beyond the 20 percent cost contingency, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, B2H-alternative portfolio under planning conditions. This cost difference is illustrated in the *Second Amended 2019 IRP* Table 9.7. The best B2H Portfolio is PGPC B2H (1), and the best B2H-alternative Portfolio is PGPC (2). Under planning conditions, the NPV difference in cost between these portfolios is about $35 million. This $35 million, compared to the total $108 million NPV of Idaho Power's share of the B2H project, including the 20 percent cost contingency, represents a large gap and illustrates a low capital-cost risk.

Market Price Risk

Idaho Power performed two separate risk analyses on the 24 resource portfolios developed by the AURORA model for the *Second Amended 2019 IRP*. Under the first risk analysis, total portfolio costs (i.e., total of fixed and variable costs) were modeled under three higher-priced natural gas and carbon cost scenarios. The second risk analysis was a stochastic risk analysis, where total portfolio costs were modeled for 20 iterations, or futures, on the following stochastic risk variables: natural gas price, customer load, and hydro condition. These analyses are described in Chapter 9 of the *Second Amended 2019 IRP*.

Idaho Power emphasizes that wholesale electric market prices are not specified inputs to the AURORA model, but rather are output by the model in response to various factors and are strongly driven by positive correlations with natural gas price and carbon cost, and a negative correlation with hydro condition. Thus, the risk analyses performed by Idaho Power are considered to study the relative exposure of the IRP resource portfolios to the studied inputs (e.g., natural gas price), and by extension to wholesale electric market prices output by the AURORA model.

The risk analyses performed for the *Second Amended 2019 IRP* indicate that total portfolio costs, specifically variable costs associated with the operation of portfolio resources (e.g., cost of imported wholesale electric energy), are markedly affected by the studied risk variables. For example, the total portfolio costs for Portfolio PGPC B2H (1) had a $3 billion range between planning case conditions for natural gas price and carbon cost and high case conditions for both inputs (Table 9.7 of the *Second Amended 2019 IRP*). Similarly, Portfolio PGPC B2H (1) costs ranged by about $2 billion across the 20 stochastic iterations (Figure 9.6 of the *Second Amended 2019 IRP*). Thus, the risk analyses indicate that the studied risk variables strongly influence portfolio costs. However, the analyses also importantly suggest that the relative exposure to the studied risk variables, including by extension wholesale electric market prices, does not dramatically favor one portfolio over another; Portfolio PGPC B2H (1) and other B2H-based portfolios exhibit similar ranges in their portfolio costs across the risk scenarios as B2H-alternative portfolios.

Liquidity and Market Sufficiency Risk

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak. Idaho Power's peak occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

Data Point 1. Peak Load Analysis from Table 6

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest[17] have forecast 2028 winter peaks that exceed their forecast 2028 summer peaks by a combined 8,300 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2023—Northwest Power Conservation Council Report

Idaho Power's review of recent assessments of regional resource adequacy in the Pacific Northwest included the *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the Northwest Power and Conservation Council (NWPCC) Resource Adequacy Advisory Committee (RAAC). 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,[18] 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 megawatts 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). 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.

[17] Load serving entities from Table 6 included in stated figure are Avista, BPA, British Columbia, Chelan, Grant, PacifiCorp—West, Portland General, Puget Sound, Seattle City, and Tacoma.

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

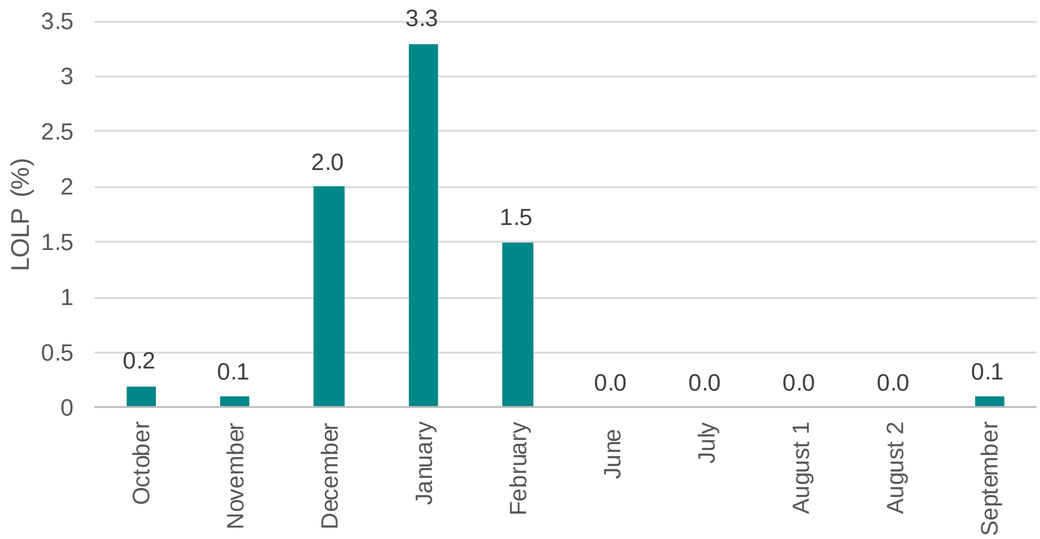

Figure 9. **LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023**

Data Point 3: 2018 Pacific Northwest Loads and Resources Study—BPA

Idaho Power's review of recent regional resource adequacy assessments also included the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[19] Idaho Power concludes from this analysis that: 1) summer capacity will be available in the future, and 2) additional summer capacity will likely be added as the region adds resources to meet winter peak demand. BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled 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:

[19] 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

Table 10 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

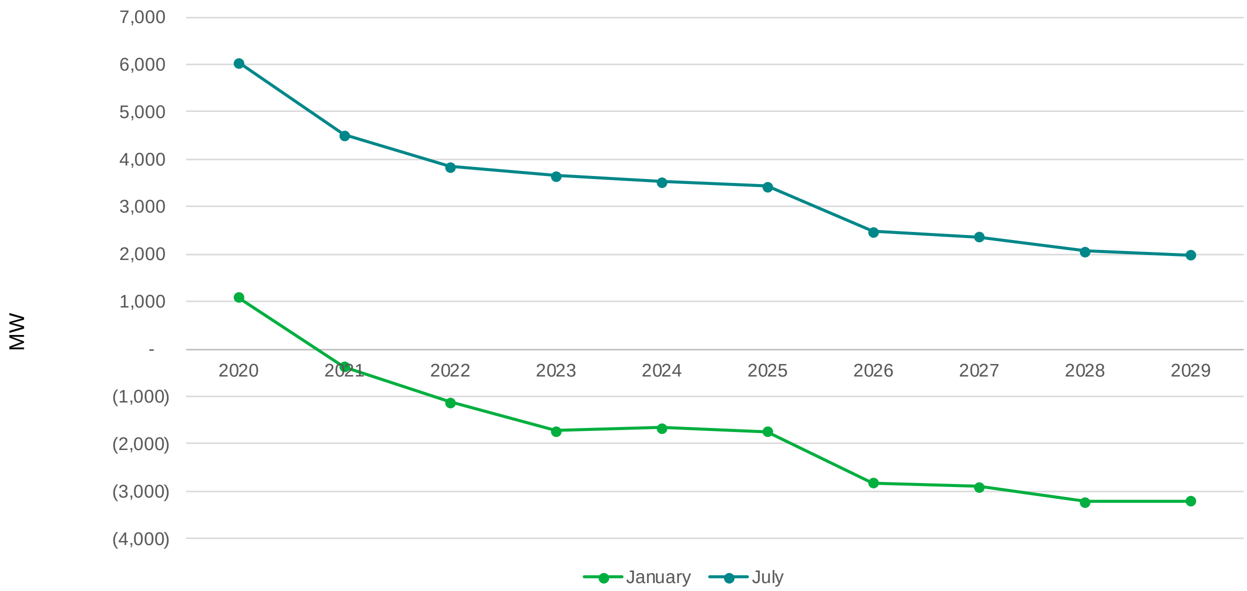

Figure 10. BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Data Point 4: FERC Form 714 Load Data

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 11.

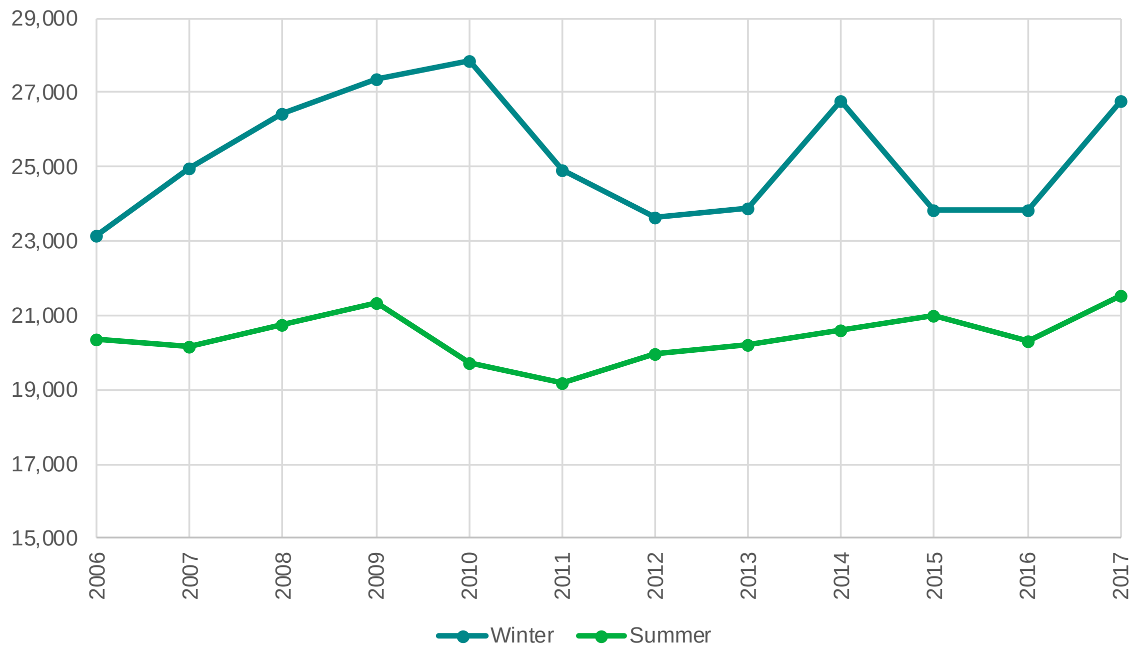

Figure 11. Peak coincident load data for most major Washington and Oregon utilities

Figure 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 (winter peaking), 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 (more water in summer compared to winter).

Data Point 5: Northwest and California Renewable Portfolio Standards

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in more solar generation throughout the region and may also result in the addition of dispatchable flexible ramping resources, such as the Port Westward 2 power plant installed by Portland General Electric in 2014.

Market Sufficiency and Liquidity Conclusions

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, risk analyses conducted in the *Second Amended 2019 IRP* indicates B2H remains cost competitive over a wide range of risk scenarios, including variations in market prices because of variations in input variables.

Coparticipant Risks

Idaho Power, BPA, and PacifiCorp, collectively referred to as coparticipants or funders, are fully engaged in permitting activities. and have had ongoing construction and operating agreement discussions.

Under the terms of the Joint Permitting Agreement, the funders may withdraw from the agreement at any time and for no reason. In such an event, the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

In the event that either BPA or PacifiCorp were to decide not to move forward with the project, Idaho Power believes other parties may have interest in potential ownership in B2H. At least one additional party was involved in the original negotiations that ultimately led to the current three-party 2012 Joint Permitting Agreement. Additionally, Idaho Power has had discussions with other entities that may have interest in the B2H project. In fact, it is entirely possible that additional partners may commit to the project – even assuming BPA and PacifiCorp remain committed. Any consideration of additional project coparticipants would be discussed and agreed on by the current funders.

As noted in the *Second Amended 2019 IRP* Boardman to Hemingway Participant Update of Chapter 1, 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.

Nevertheless, changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk by authorizing the project on 85.6 miles of BLM-administered land. The U.S. Forest Service also issued a ROD authorizing the project on 8.6 miles of National Forest land in 2018, and the U.S. Navy issued a ROD in 2019 authorizing the project on 7.1 miles of Navy land. The Oregon site certificate process is the next major step in siting; in 2020, ODOE issued the Proposed Order recommending approval of the project. While the Proposed Order are subject to a Contested Case proceeding, the Proposed Order is a major milestone in the state permitting process and the recommendations are certainly encouraging. Idaho Power believes that the significant progress in both federal and state permitting processes minimizes future siting risk.

Schedule Risk

As of the date of this appendix, Idaho Power's scheduled B2H in-service date is 2026 or later. At a high level, remaining activities prior to energization are: permitting, coparticipant agreements, preliminary construction, material procurement, and construction.

As noted above, the permitting phase of the project is ongoing. For federal permitting, the B2H project achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017 and subsequent Right-of-Way Grant in January 2018. The ROD and ROW Grant formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The U.S. Forest Service ROD was issued in November 2018 and a right-of-way easement was issued in May 2019. A Navy ROD was issued in September 2019 and a Navy easement was issued in May 2020. The project is on track to receive the federal notice to proceed in late 2022 or early 2023.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the Amended Application for Site Certificate to the ODOE and an application completeness determination from ODOE in fall 2018. The ODOE also issued a Draft Proposed Order in May 2019. A Proposed Order was issued in July 2020, and a Final Order and Site Certificate are expected in 2021. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the EFSC does not issue a Site Certificate in 2021.

With the receipt of the BLM ROD and ROW easement, and a Proposed Order from ODOE, sufficient route certainty exists to continue with preliminary construction tasks. In 2019, Idaho Power began the process of acquiring necessary federal authorizations to conduct geotechnical explorations. At the time of writing, Idaho Power is in the process of initiating the following activities for 2021: detailed design, ROW option acquisition, legal surveys, and geotechnical investigation. LIDAR (aerial mapping) has been recently completed for the entire B2H route and any proposed alternatives. Construction activities are expected to commence in 2023 with the expected project in-service date in 2026.

Catastrophic Event Risk

As detailed in B2H Design section of this appendix, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity and an additional path to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system. Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

Project Activities

Schedule Update

Permitting

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017 and the ROW Grant on January 9, 2018. These actions formalized the conclusion of the siting process and federally required NEPA process. The BLM ROD and ROW Grant provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. With the issuance of the U.S. Forest Service ROD and easement, and the issuance of the U.S. Navy ROD, all major federal decision records have been achieved.

For the State of Oregon permitting process, Idaho Power submitted the Amended Application for Site Certificate to the ODOE in summer 2017 and ODOE issued a Draft Proposed Order in May 2019 and a Proposed Order in July 2020. A Final Order and Site Certificate is expected in 2021.

The NEPA and EFSC processes are separate and distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a "desktop" level. Information is brought into the process on a phased-approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analyses to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy, coming in at over 20,000 pages.

Post-Permitting

To achieve an in-service date in 2026, preliminary construction activities must commence parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys (light detection and ranging (LiDAR) aerial mapping

- Sectional surveys
- ROW acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction. The material acquisition and construction activities are expected to take approximately 3 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project coparticipants.

CONCLUSIONS

This B2H *Second Amended 2019 IRP* appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the *Second Amended 2019 IRP*, B2H was identified as the least-cost and least-risk resource to serve future capacity and energy future needs. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is nearly 60 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[20] In addition to the B2H capacity benefits, B2H is expected to have the lowest levelized cost of energy—lower than the expected costs for a combined-cycle gas plant and utility-scale solar.[21]

The B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. Pursuant to EFSC's least-cost plan rule, the need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[22] The OPUC has already acknowledged the construction of B2H in Idaho Power's 2017 IRP. Idaho Power asks the OPUC to confirm its acknowledgement of B2H in the company's *Second Amended 2019 IRP*.

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[20] Amended 2019 IRP Figure 7.5.

[21] Amended 2019 IRP Figure 7.6

[22] OAR 345-023-0020(2).

Appendix D-1. Transmission line alternatives to the proposed B2H 500-kV transmission line

Table D-1

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

Scenario	Line Capacity[1]	Potential Path 14 West-East Increase[2]	Losses on New Circuit(s)[3]
a. Longhorn to Hemingway 230 kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230 kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345 kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500 kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500 kV—two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500 kV double circuit	6,428 MW	1,235 MW	2.9%
g. Longhorn to Hemingway 765 kV single circuit	4,770 MW	1,200 MW	2.4%

1 Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

2 Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

3 Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

Table D-2

Comparison of Transmission Line Capacity Scenarios—Rebuild Existing Lines to the Northwest

Scenario	Line Capacity[1]	Potential Path 14 Increase[2]	Losses on New Circuit(s)[3]	Length of Line/ New ROW[4]
h. Replace Oxbow-Lolo 230 kV with Hatwai–Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles/136 Miles
i. Replace Oxbow-Lolo 230 kV with Hatwai–Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles/167 Miles
j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap–Hemingway 500 kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles/150 Miles
k. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap–Hemingway 500 kV—No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles/181 Miles
l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway.	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles/168 Miles

1 Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

2 Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

3 Estimated Losses are percent losses for the new line at the Potential Rating west-east loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

4 In addition to utilizing existing 230 kV right-of-way ("ROW"), each of the scenarios above will require new ROW to be obtained.

Appendix D-2. Detailed list of notable project milestones

- June 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka "Bombing Range")
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of the Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – The BLM issues a Record of Decision (ROD) for the B2H project. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

- January 9, 2018 – BLM and Idaho Power sign the BLM ROW Grant for the B2H project.
- September 21, 2018 – ODOE determines the B2H Application for Site Certificate is complete.
- September 28, 2018 – Idaho Power files the Application for Site Certificate with ODOE.
- November 13, 2018 – The U.S. Forest Service issues a Record of Decision for the B2H project
- May 22, 2019 – The Oregon Department of Energy issues a Draft Proposed Order.
- May 28, 2019 – The U.S. Forest Service and Idaho Power sign a ROW easement agreement for the B2H project.
- May 29, 2019 – Bonneville Power Administration issues a Record of Decision for moving an existing 69 kV line from the U.S. Navy bombing range to accommodate the B2H project.
- September 2019 – U.S. Navy issues a Record of Decision for 7.1 miles of project on U.S. Navy Naval Weapons Training Facility Boardman, Oregon.
- March 23, 2020 – U.S. Navy and Idaho Power sign a ROW easement for the B2H project.
- July 2, 2020 – ODOE issues the Proposed Order and notification of the Contested Case.
- September 25, 2020 – Oregon DOJ holds Contested Cast pre-hearing conference.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

IDAHO POWER COMPANY

Attachment 2

Redline Version of
2019 Second Amended Integrated Resource Plan

October 2, 2020

IDAHO POWER®
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED—REDLINE

OCTOBER • 2020

BALANCING OUR ENERGY NEEDS • TODAY AND TOMORROW

SAFE HARBOR STATEMENT

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

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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.

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[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.

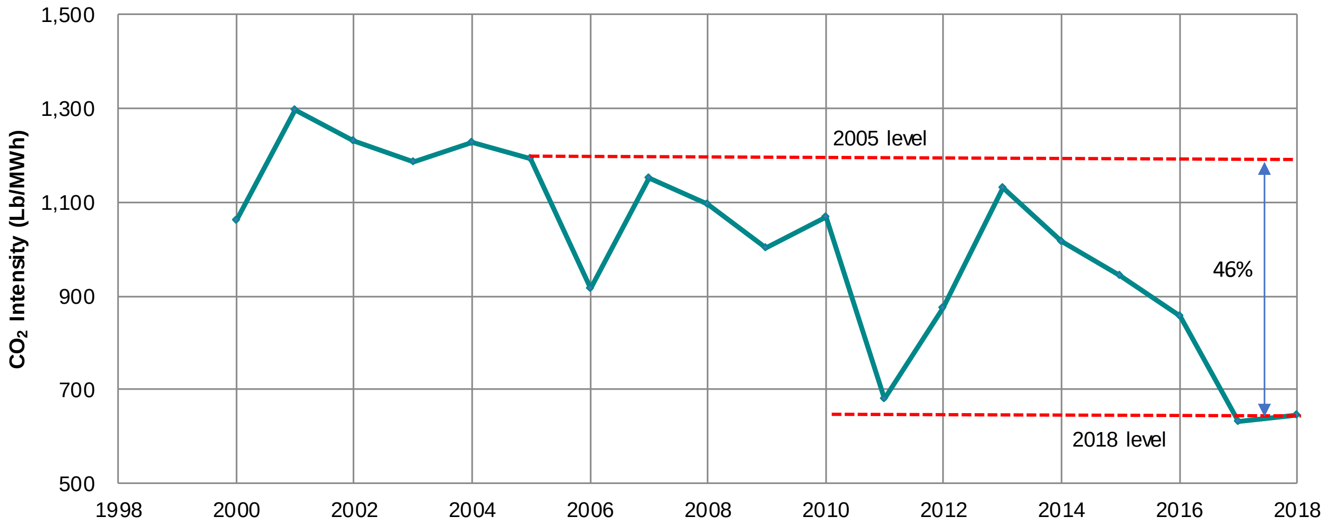

Figure 1.1 **Estimated Idaho Power CO_2 emissions intensity**

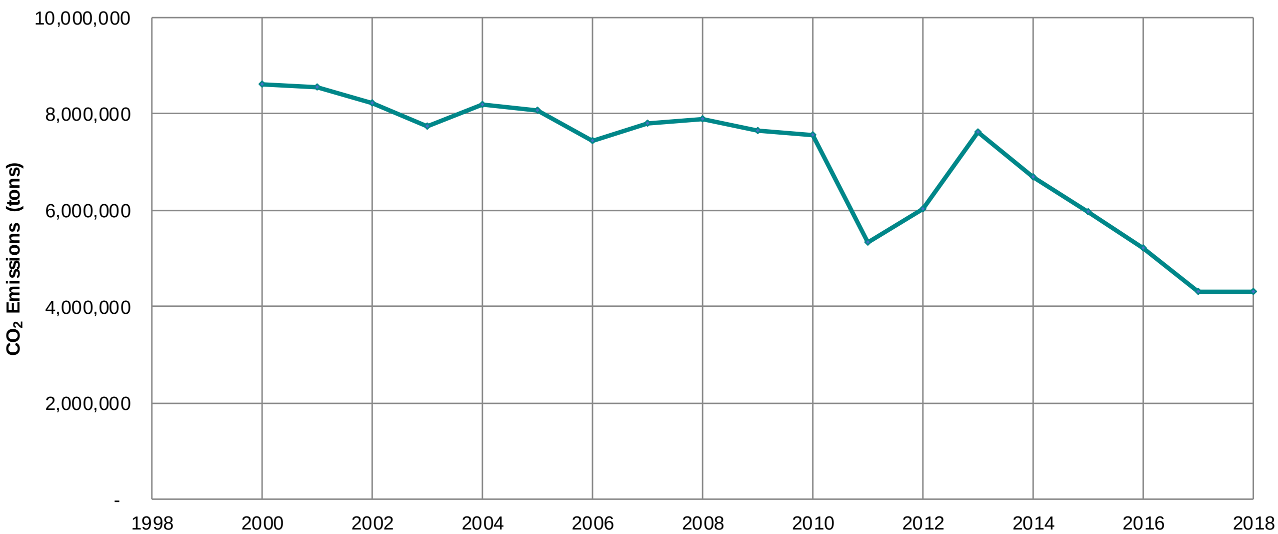

Figure 1.2 **Estimated Idaho Power CO_2 emissions**

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

Hells Canyon Dam

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.

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*.

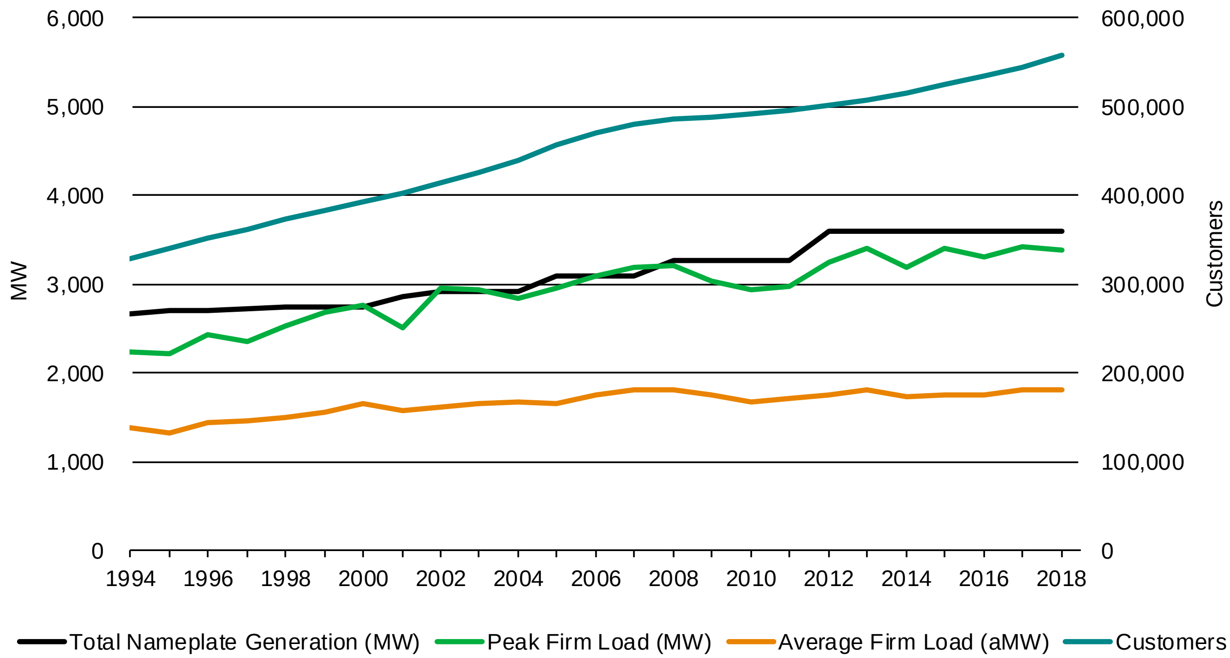

Figure 3.1 Historical capacity, load, and customer data

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.

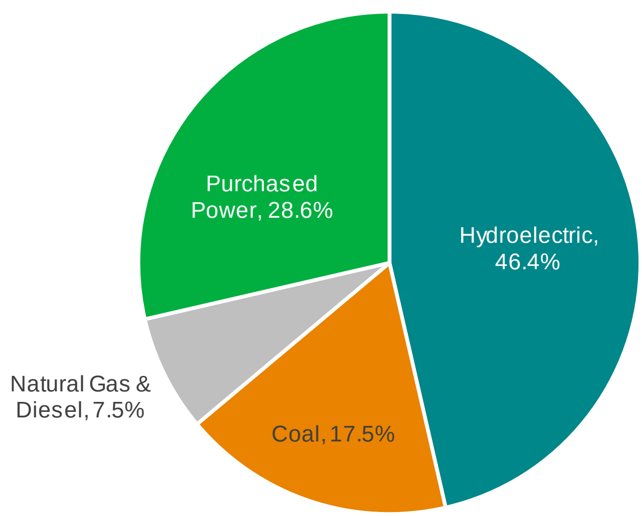

Figure 3.2 2018 energy sources

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.

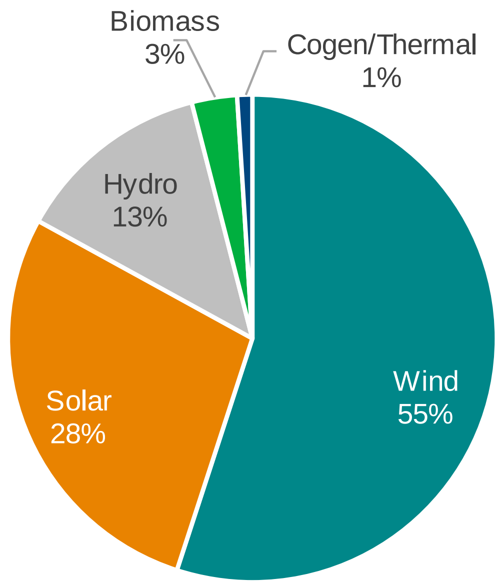


Figure 3.3 PURPA contracts by resource type

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

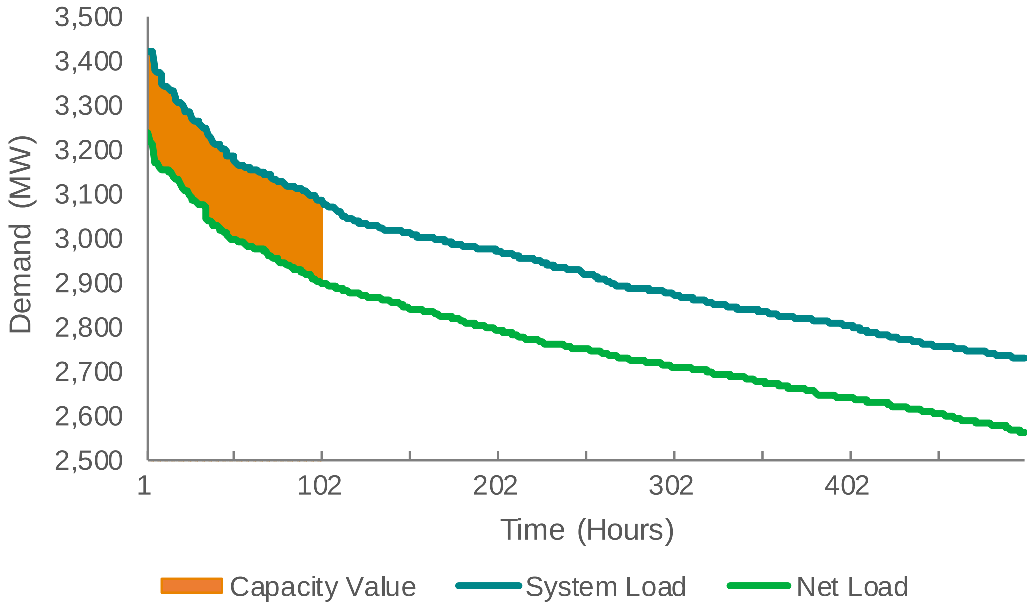


Figure 4.1 **Capacity value of solar PV**

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.

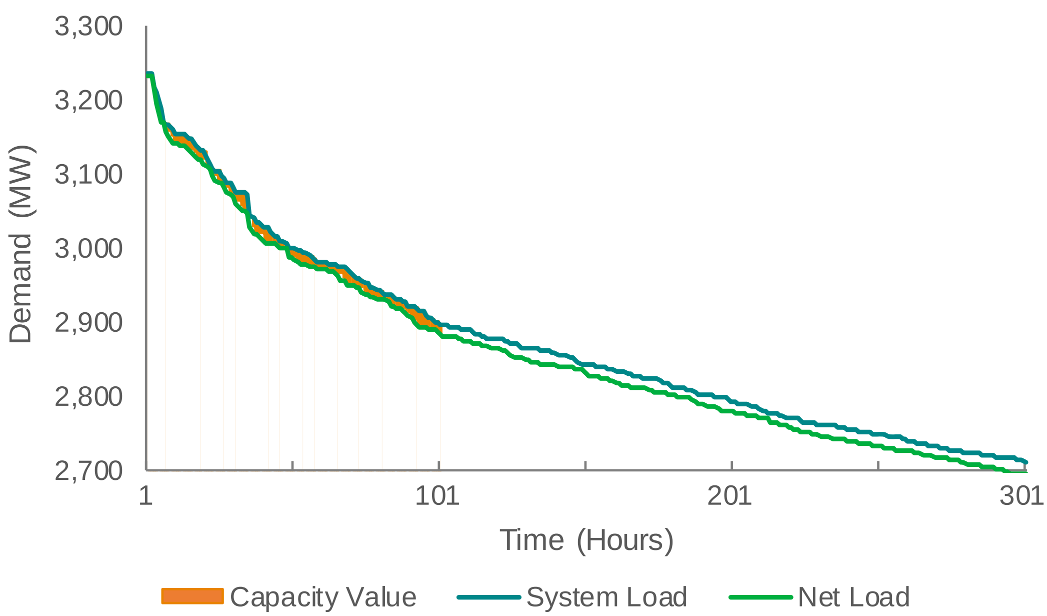


Figure 4.2 **Marginal capacity value**

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.

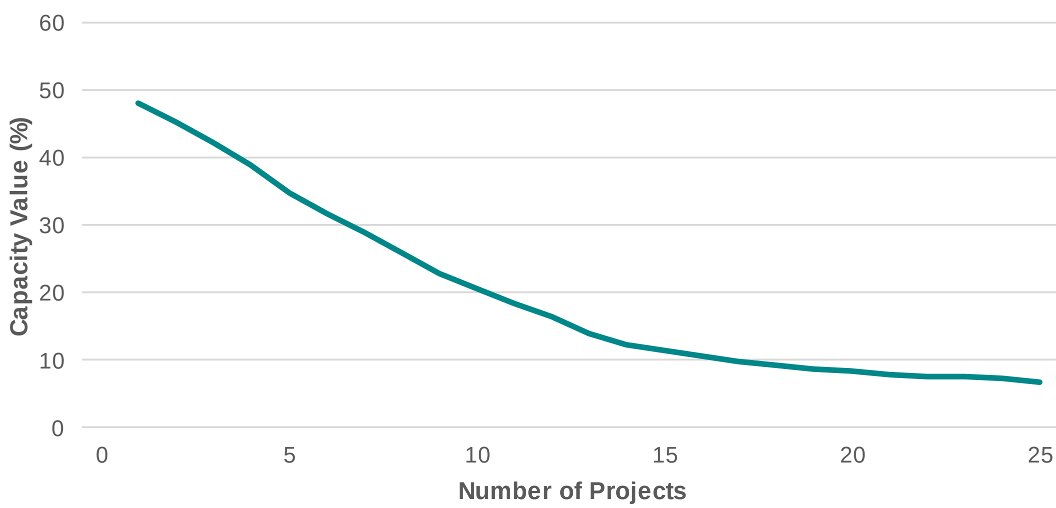


Figure 4.3 Capacity value of incremental solar PV projects (40 MW each)

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.

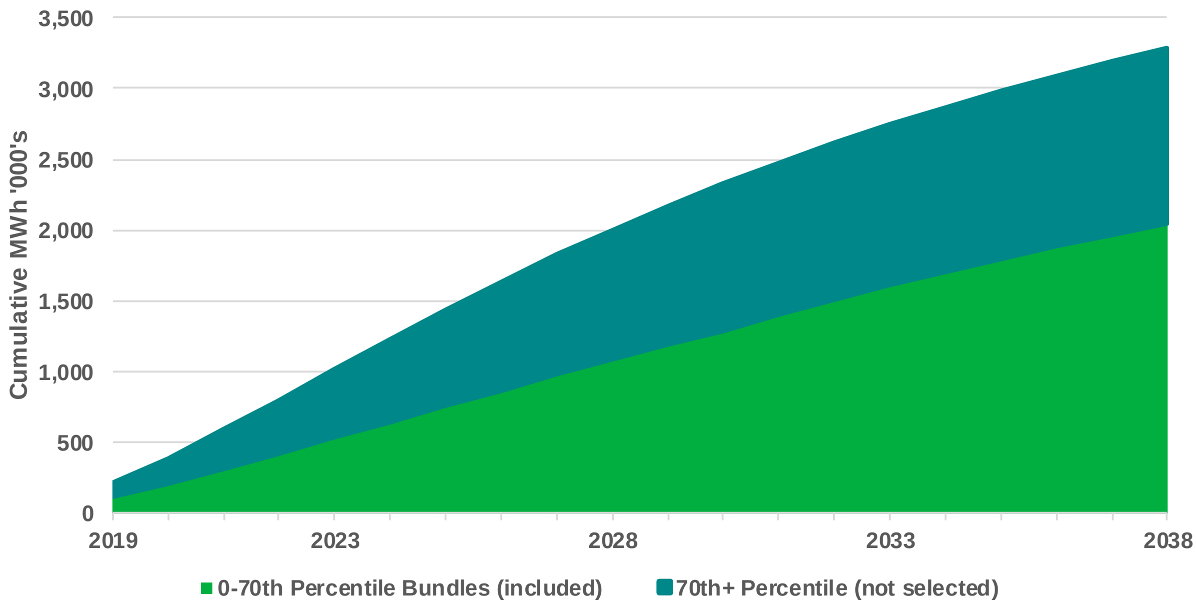


Figure 5.1 **Energy-efficient bundles selected by the IRP model and bundles that were not economically competitive and were not selected for the 2019 IRP portfolios**

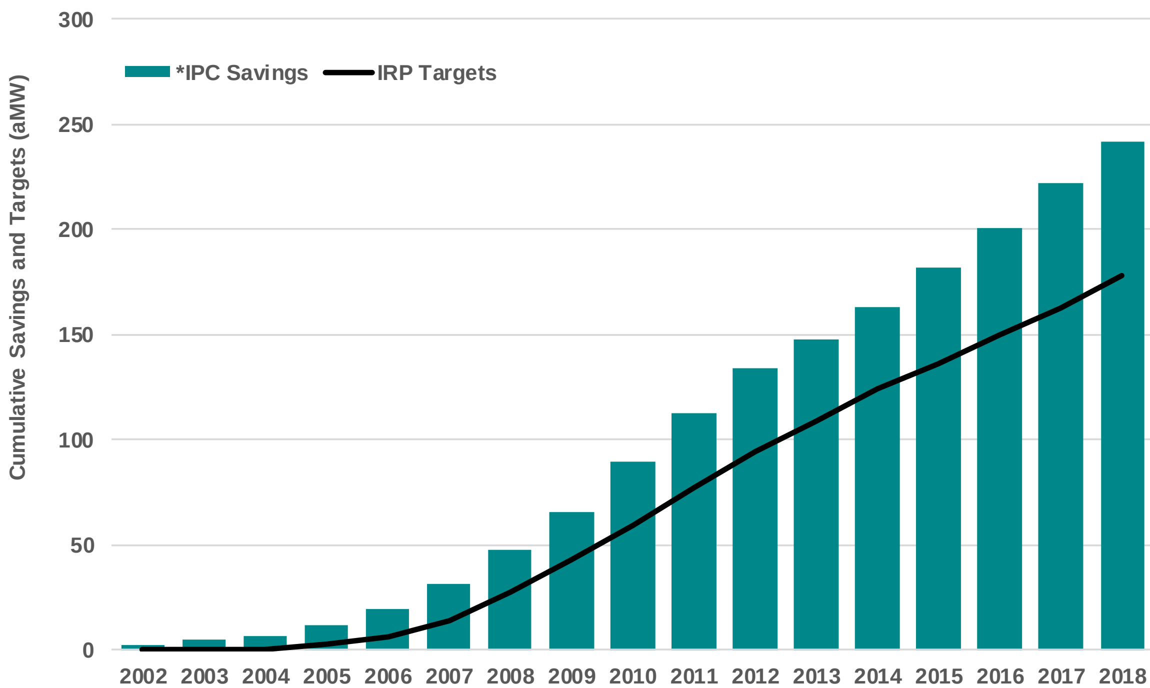
Future Energy Efficiency Potential

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 5.43 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.

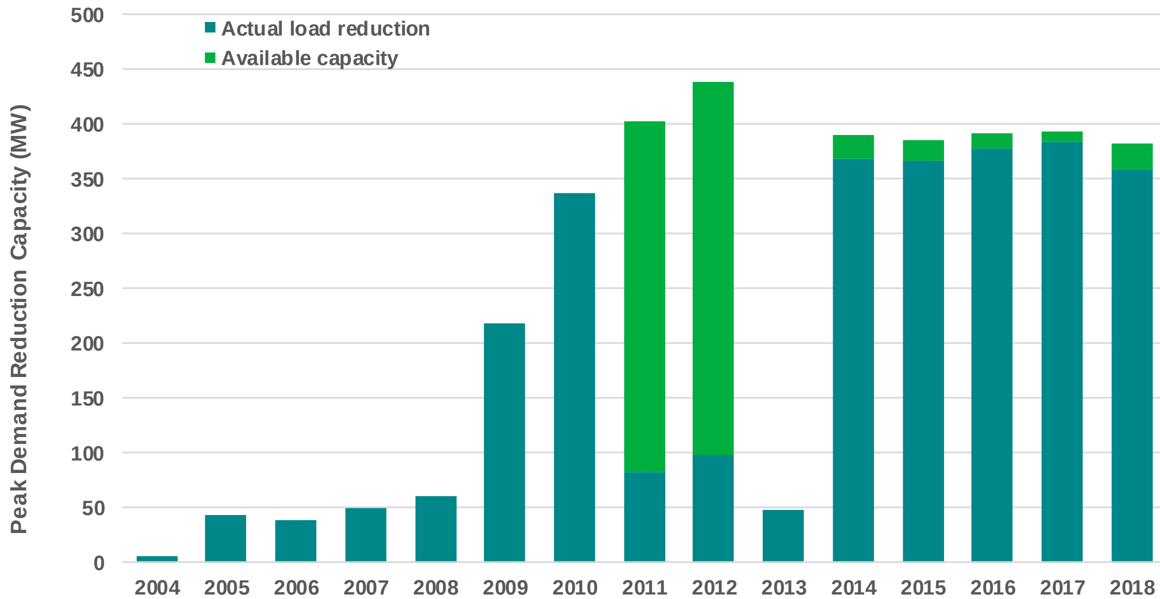


Figure 5.3 Historic annual demand response program performance

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.

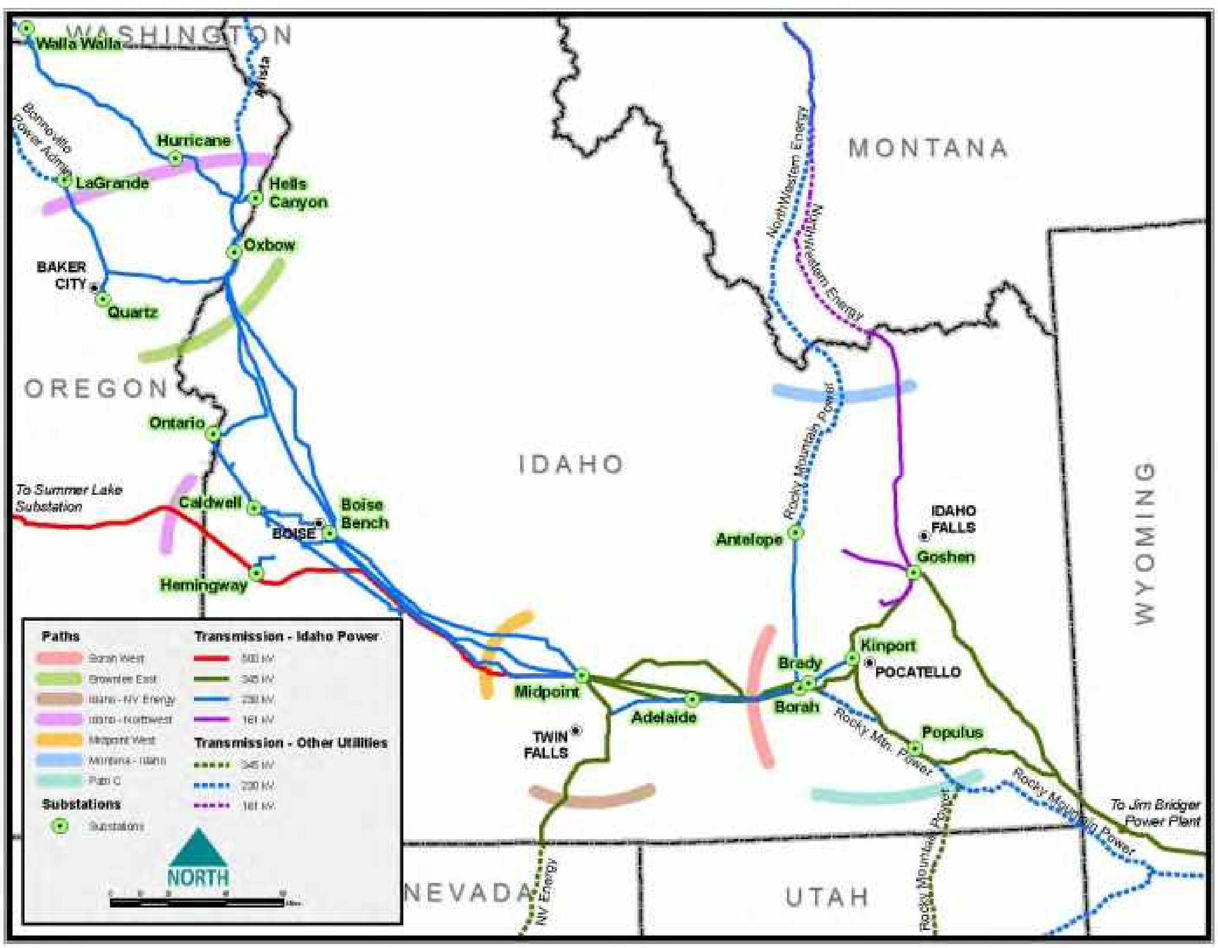


Figure 6.1 **Idaho Power transmission system map**

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.

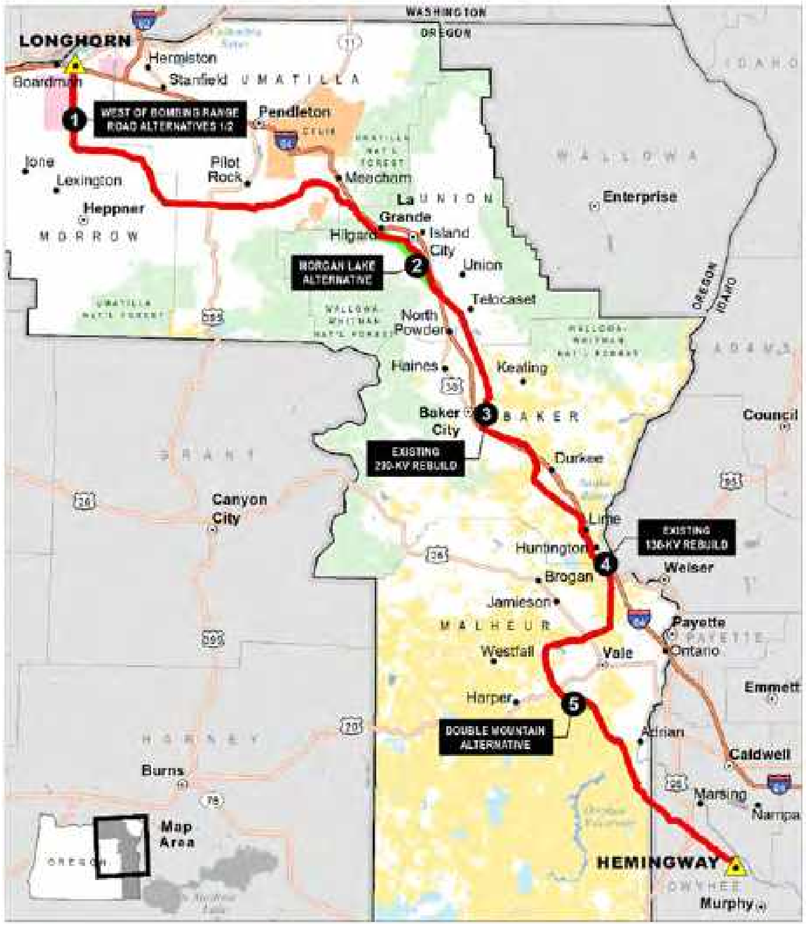


Figure 6.2 B2H route submitted in *2017 EFSC Application for Site Certificate*

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

Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather 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.

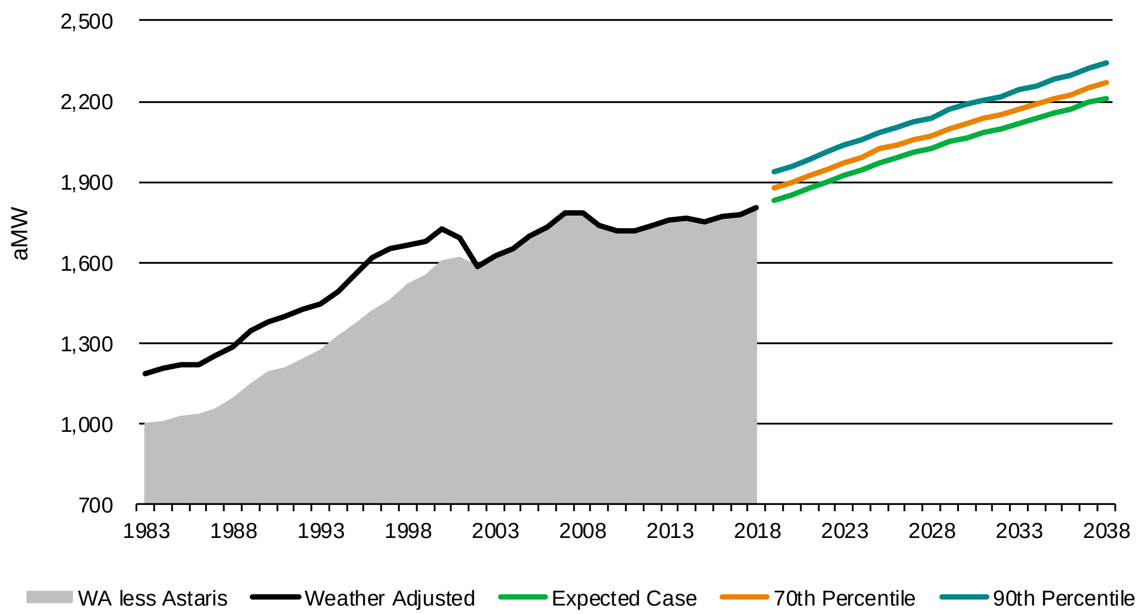


Figure 7.1 Average monthly load-growth forecast

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.

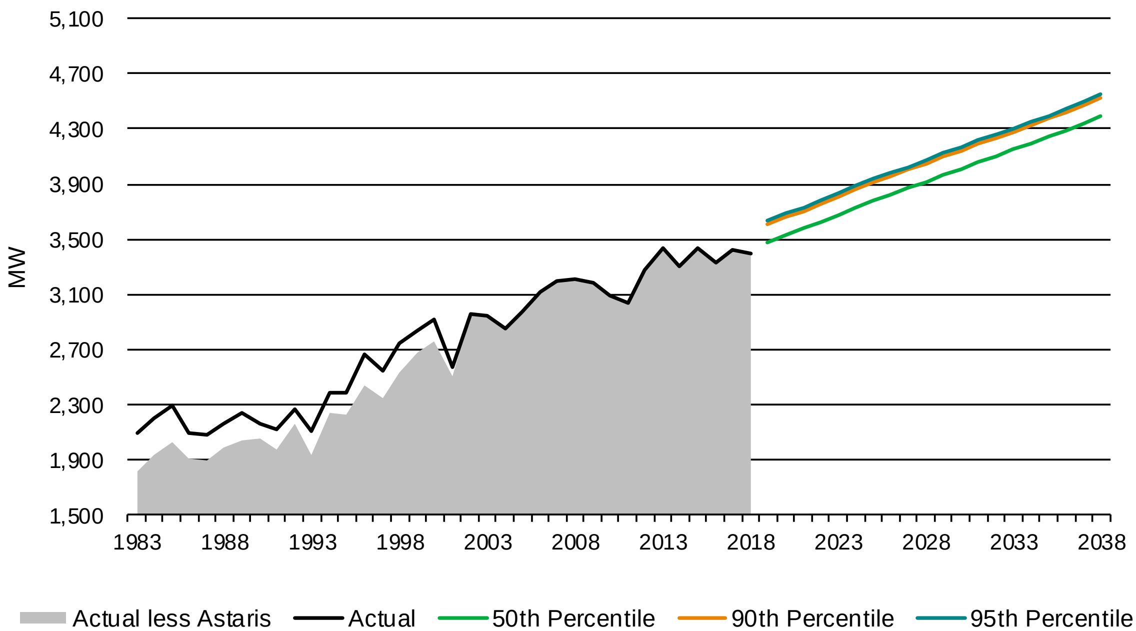


Figure 7.2 Peak-hour load-growth forecast (MW)

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 50th, 70th, and 90th 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.

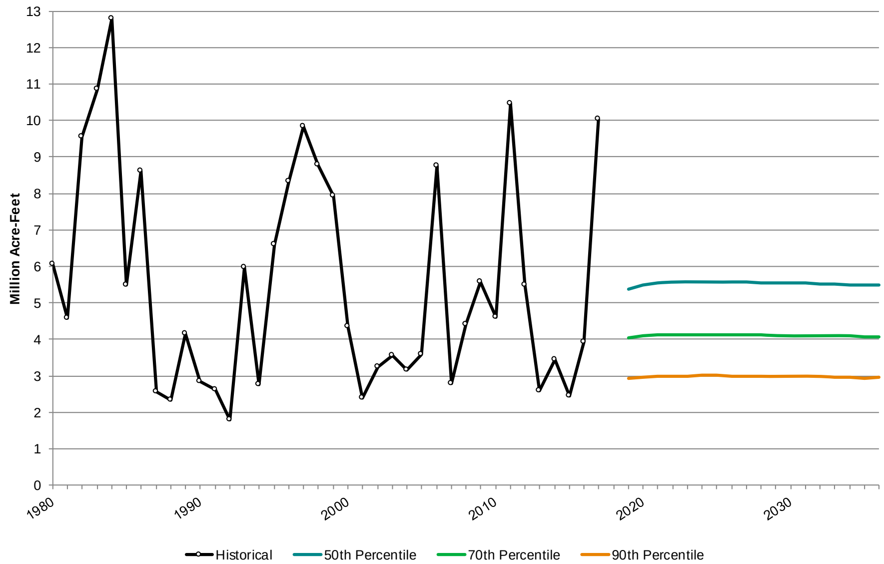


Figure 7.3 Brownlee inflow volume historical and modeled percentiles

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:

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[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

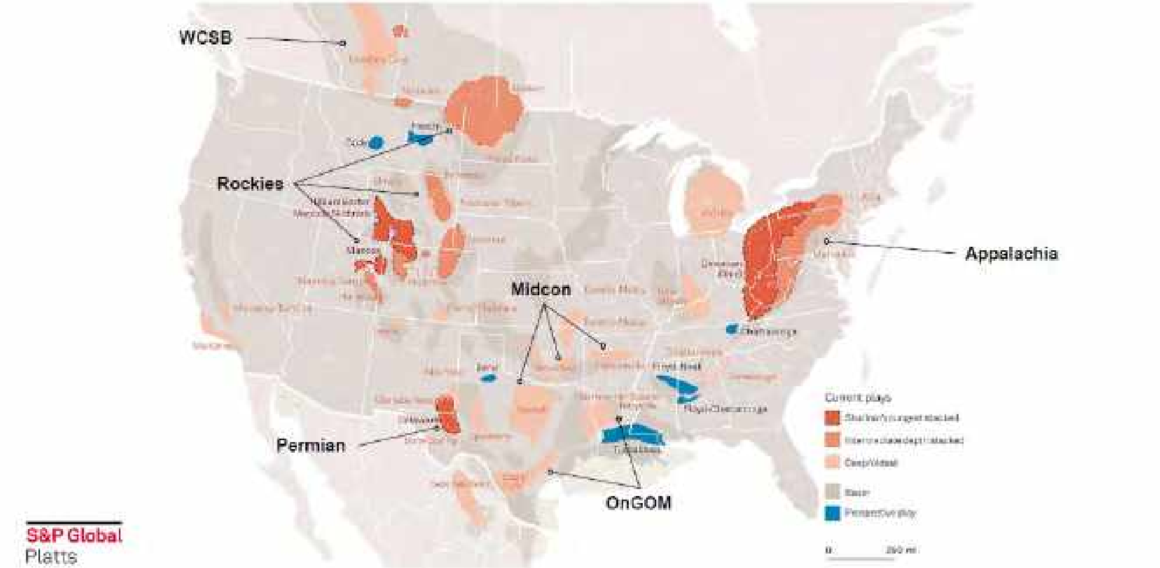


Figure 7.4 North American major gas basins

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.

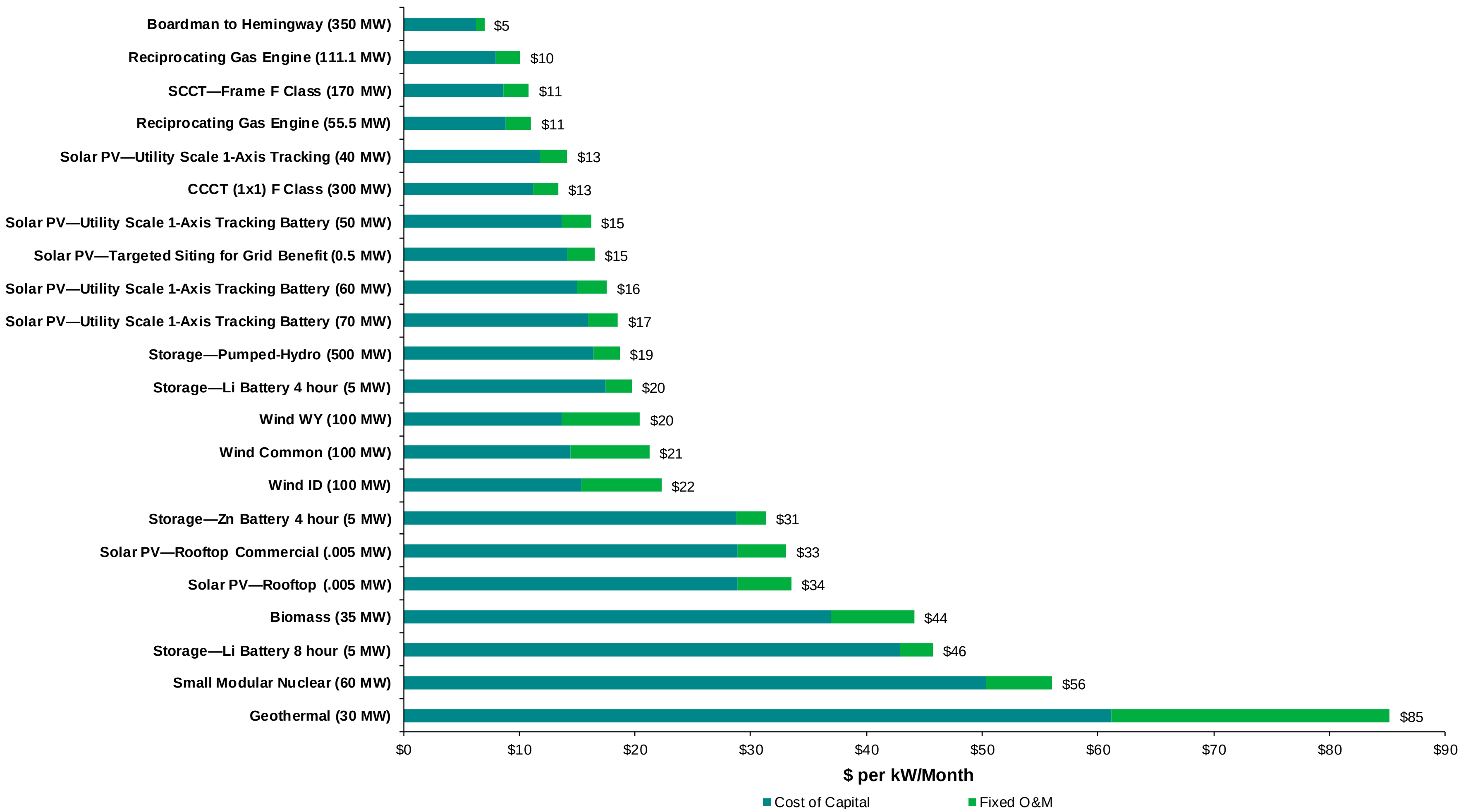


Figure 7.5 Levelized capacity (fixed) costs in 2019 dollars[15]

[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.

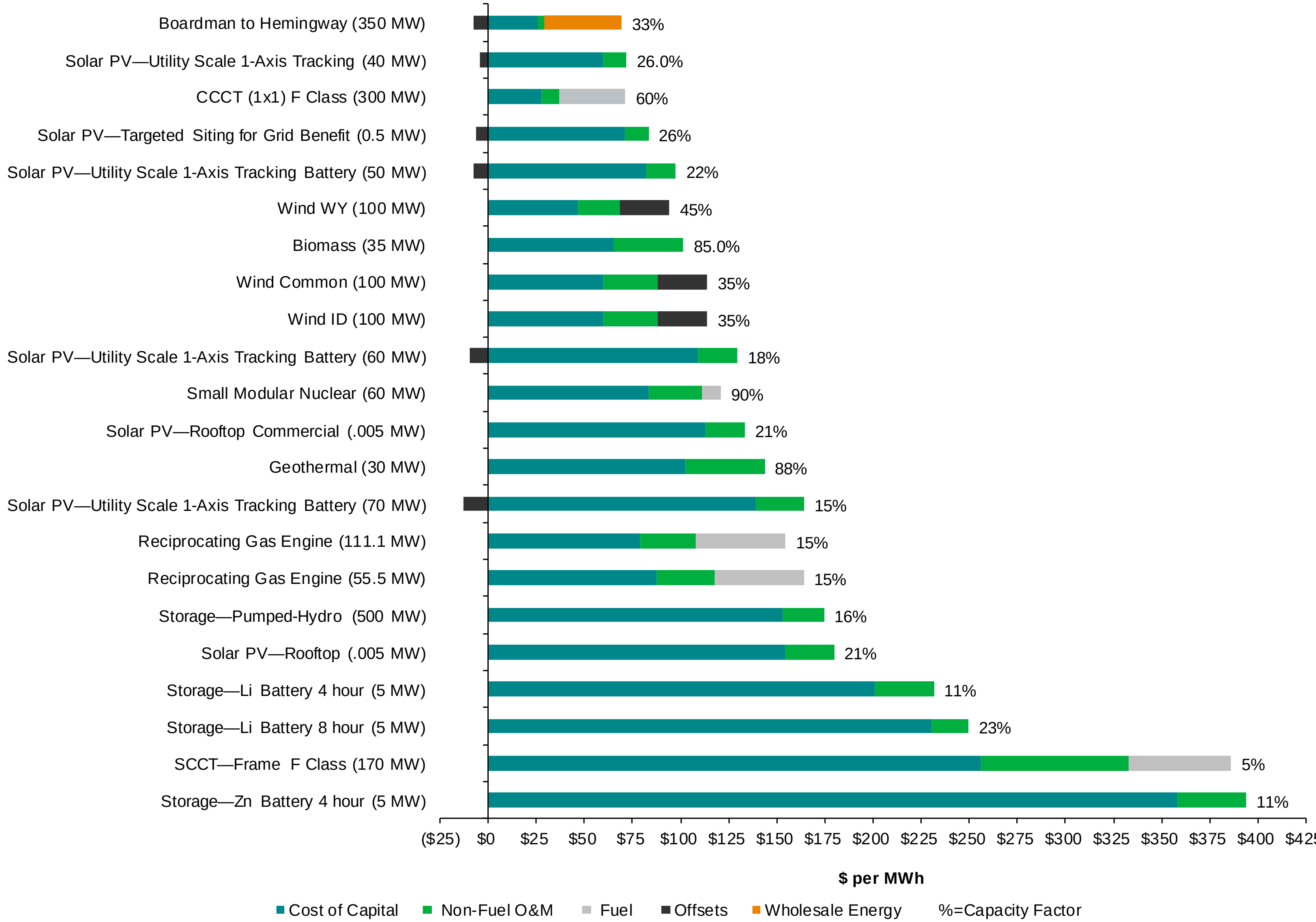


Figure 7.6 **Levelized cost of energy (at stated capacity factors) in 2023 dollars**

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.

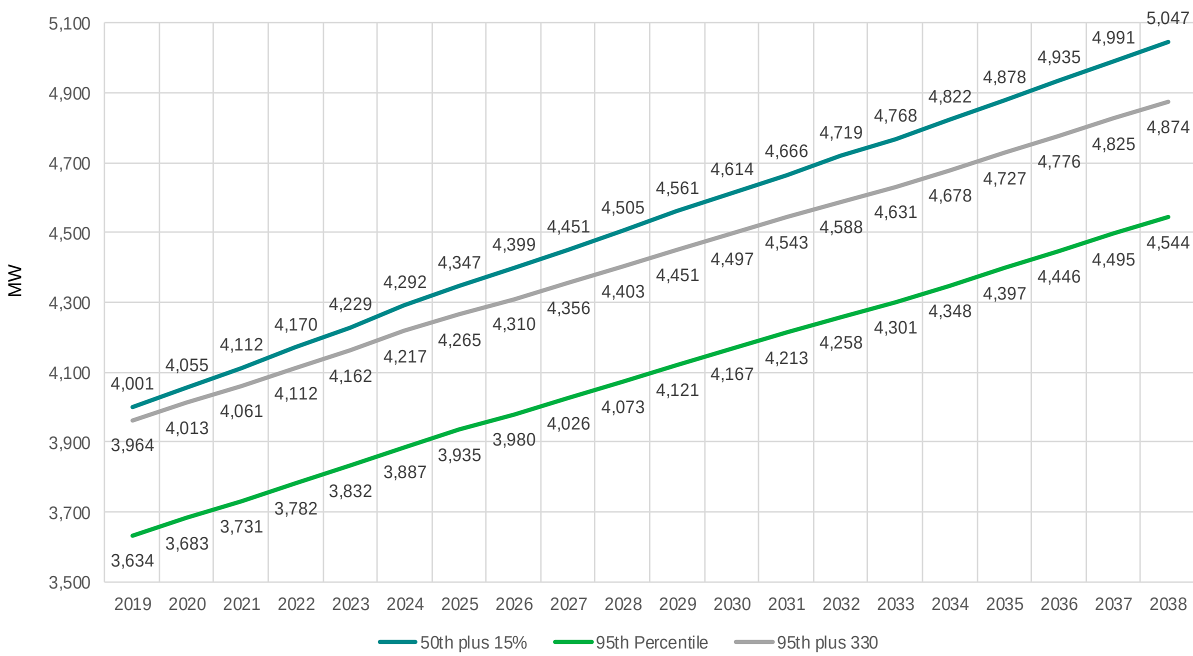


Figure 8.1 2017 versus 2019 IRP planning margin comparison (MW)

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.

[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

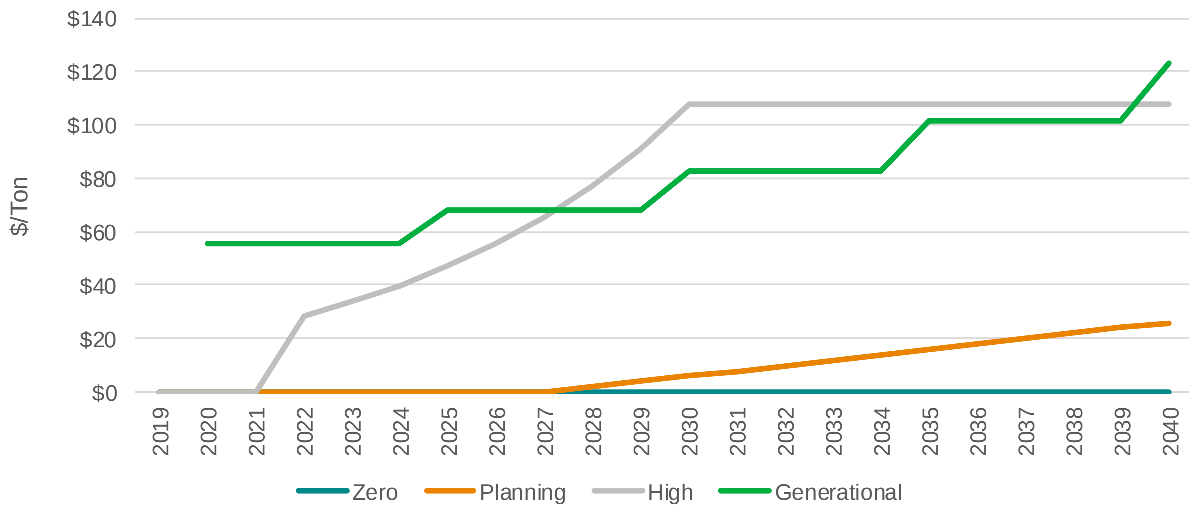


Figure 8.2 Carbon Price Forecast

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.

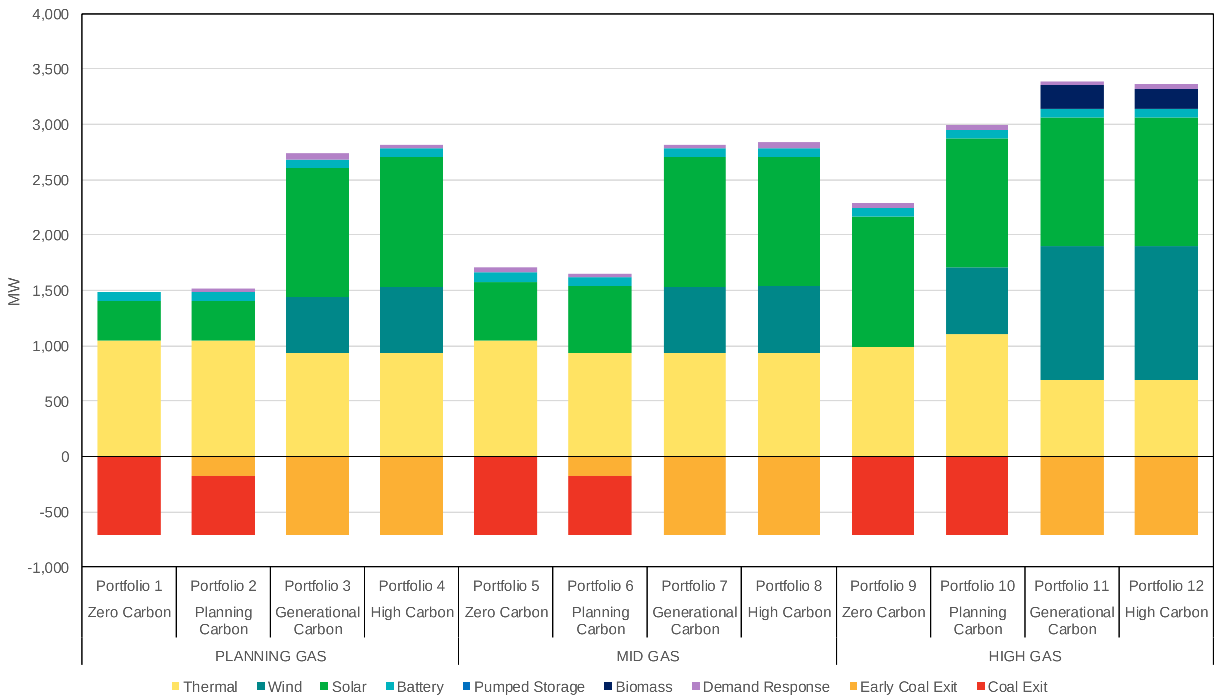
Table 8.4 shows the planned 12 B2H portfolio designs resulting from the natural gas and carbon price futures.

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*.



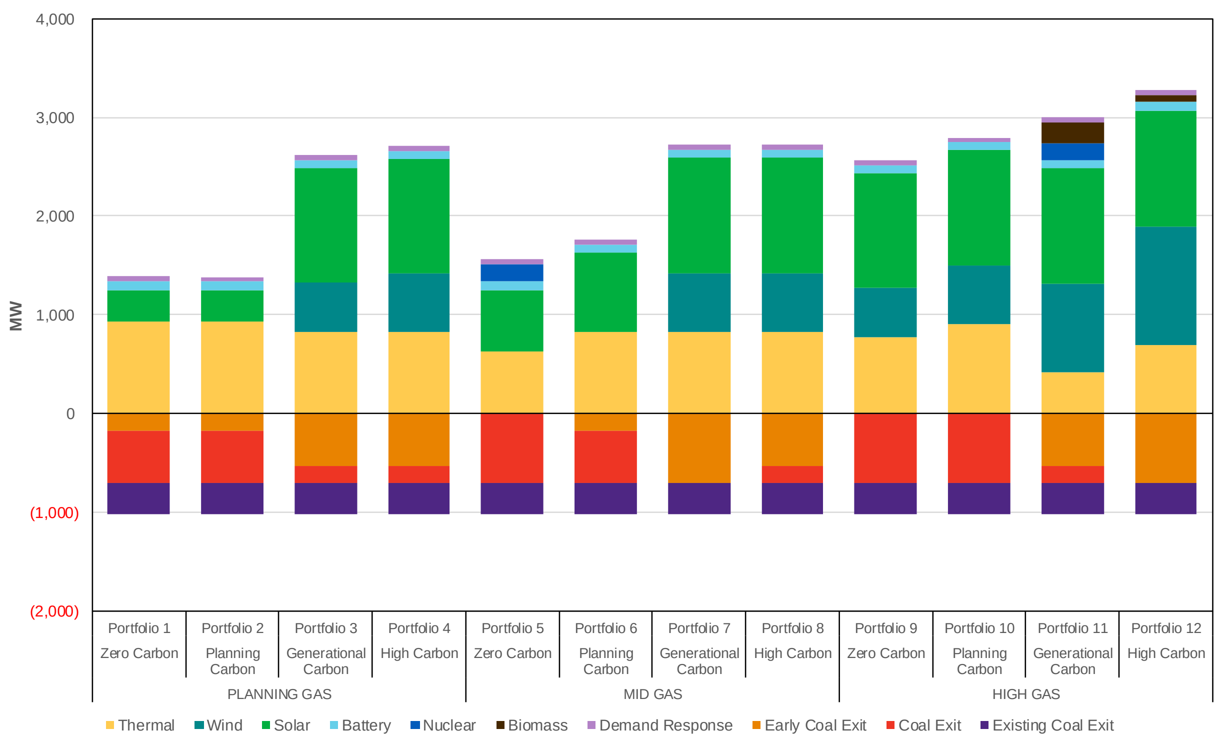
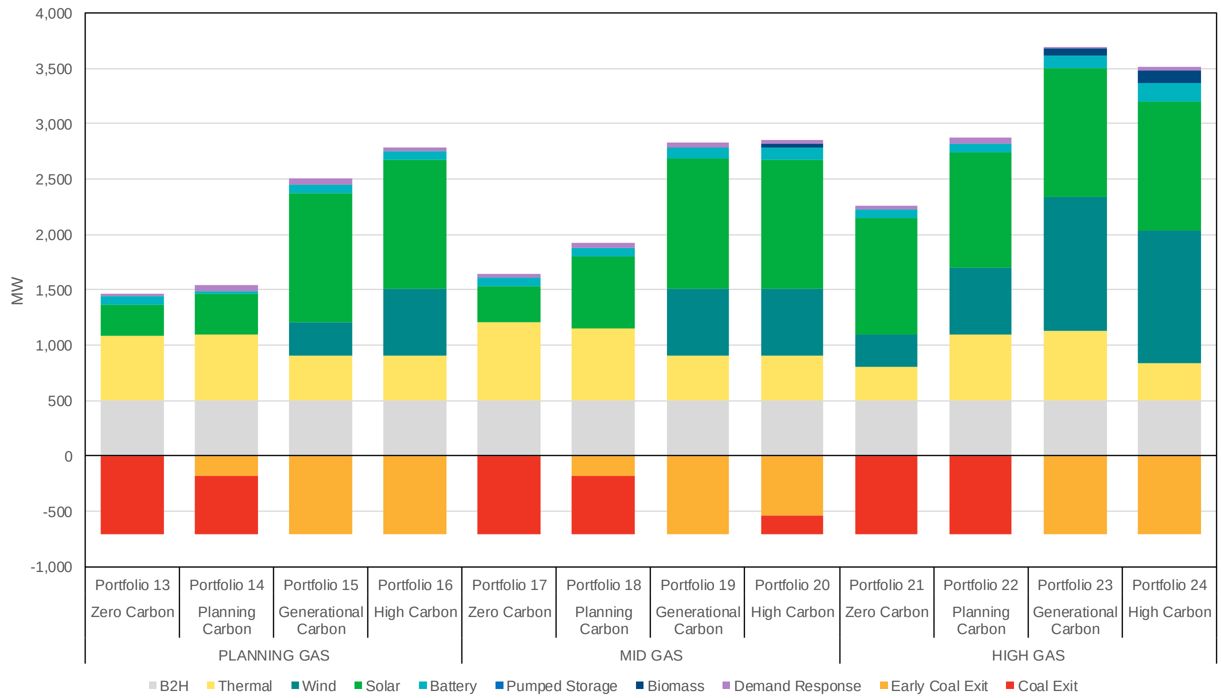


Figure 8.3 WECC-optimized portfolios 1 through 12 (non-B2H portfolios), capacity additions/reductions (MW)



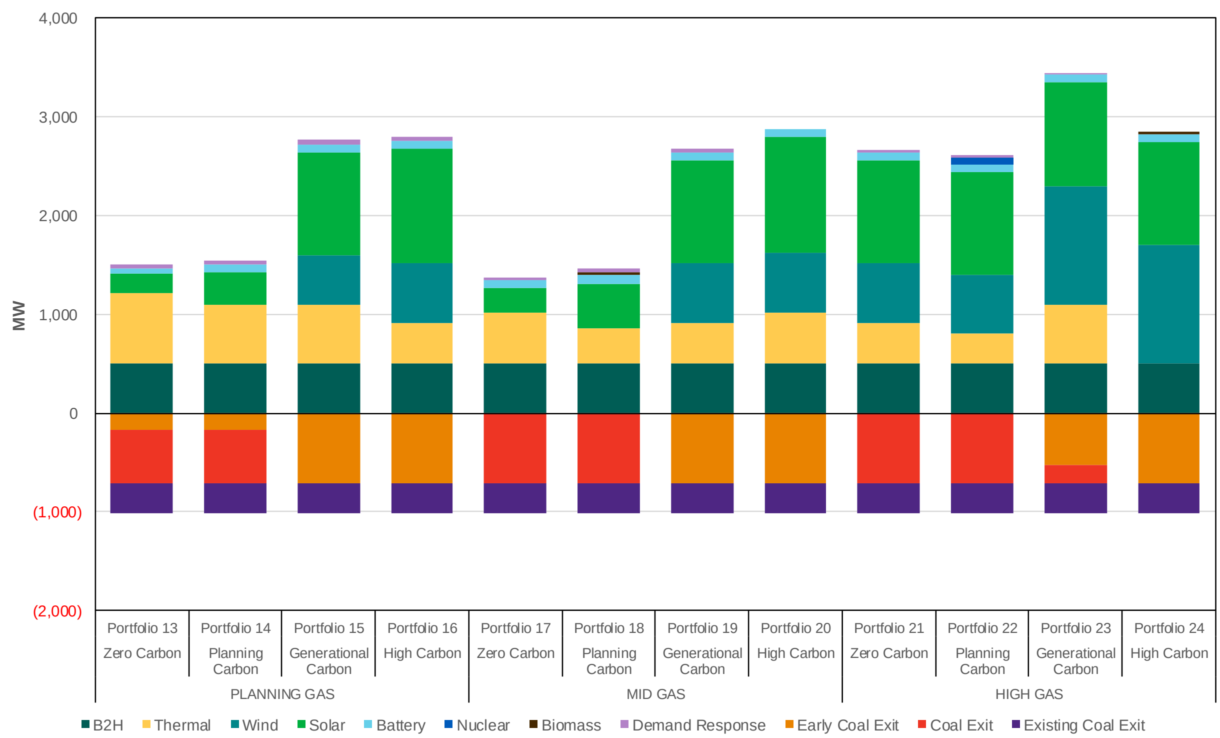


Figure 8.4 WECC-optimized portfolios 13 through 24 (B2H portfolios), capacity additions/reductions (MW)

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)

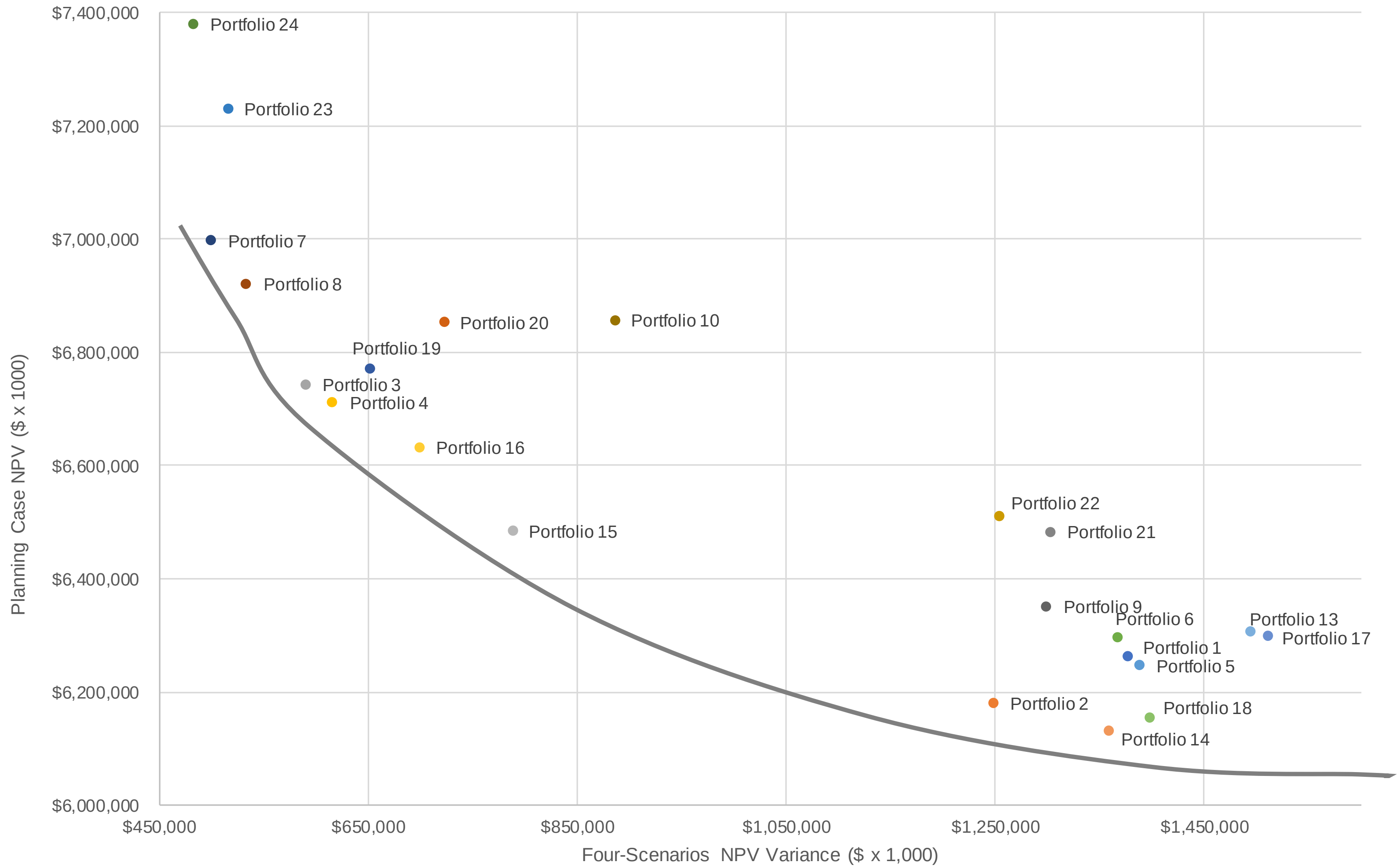
NPV ($ x 1000)	Planning Gas~~—~~, Planning Carbon	High Gas~~—~~, Planning Carbon	Planning Gas~~—~~, High Carbon	High Gas~~—~~, High Carbon
Portfolio 1	$6,~~262,350~~278,713	$~~6,983,921~~7,153,154	$8,~~615,746~~736,678	$9,~~785,216~~802,332
Portfolio 2	$6,~~180,898~~282,756	$7,~~050,988~~174,552	$8,~~268,640~~577,425	$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

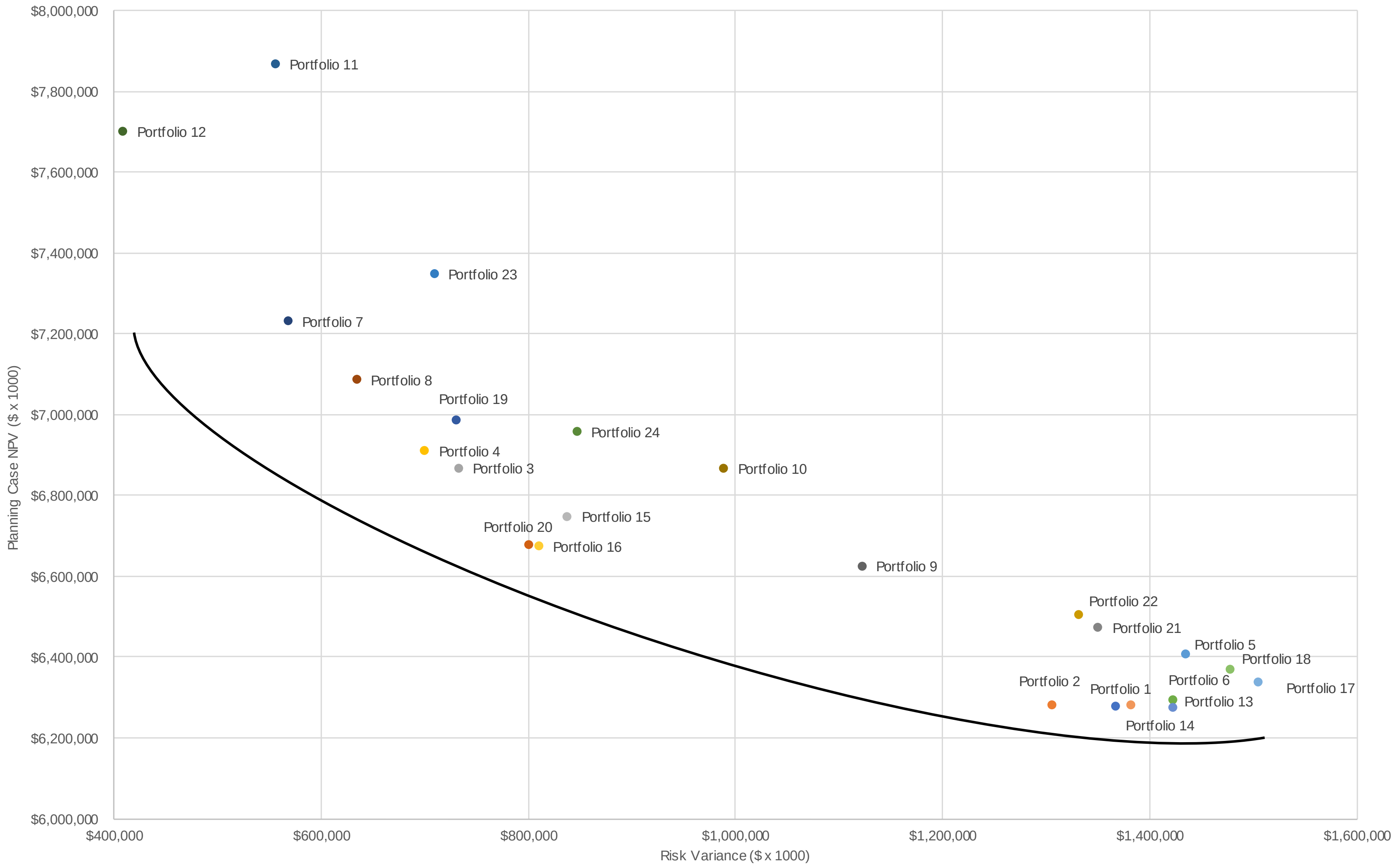


Figure 9.1 NPV cost versus cost variance

~~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.

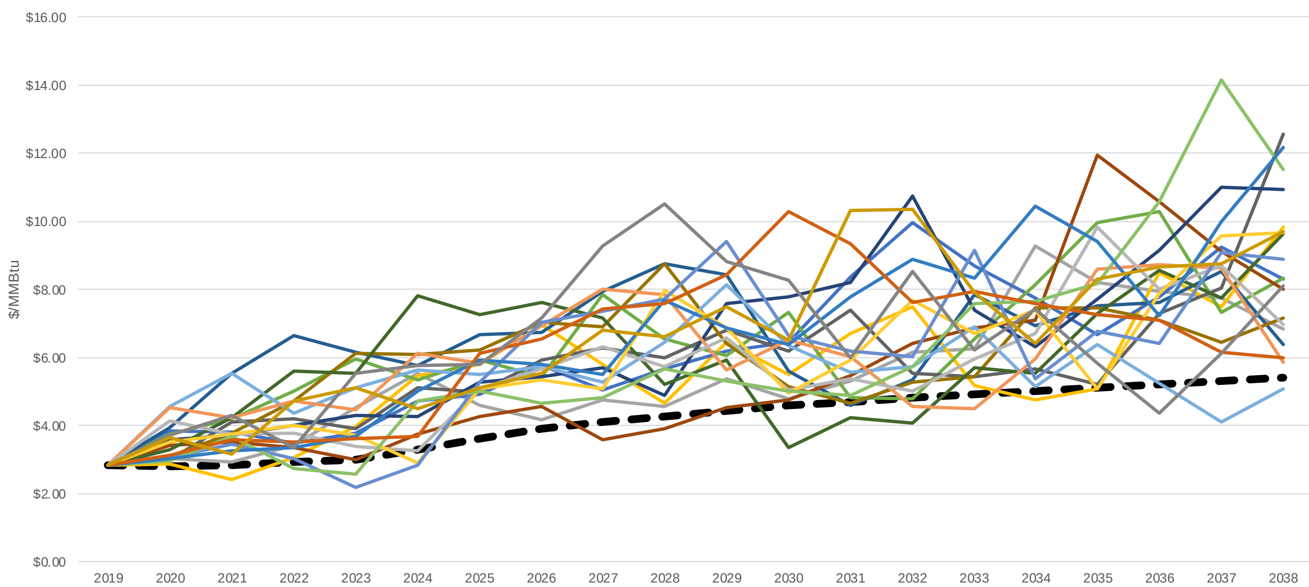


Figure 9.2 Natural gas sampling (Nominal $/MMBtu)

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

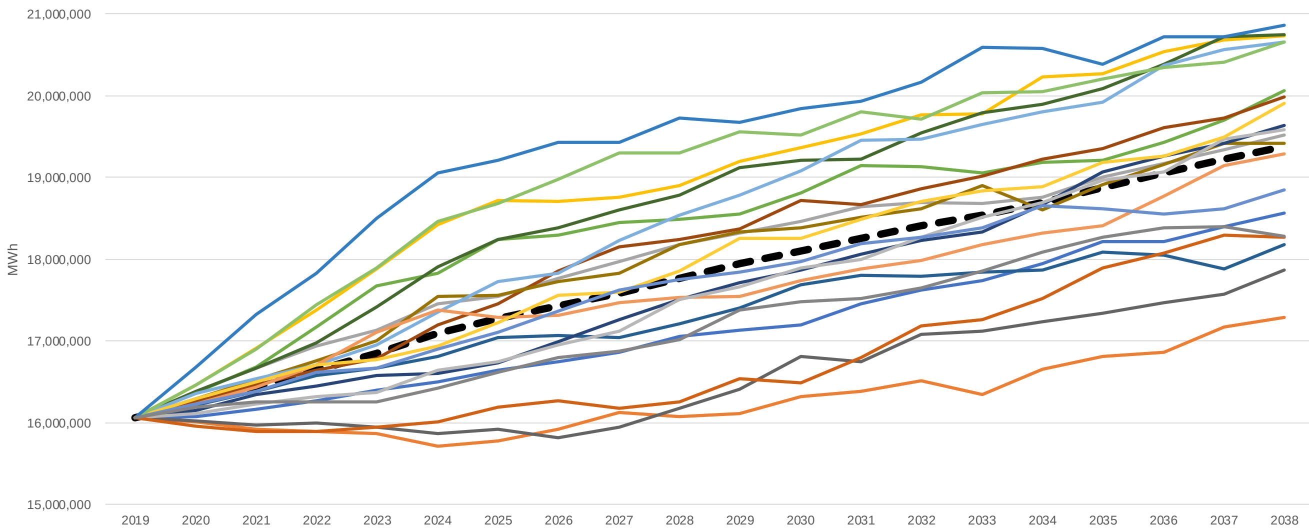


Figure 9.3 Customer load sampling (annual MWh)

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.

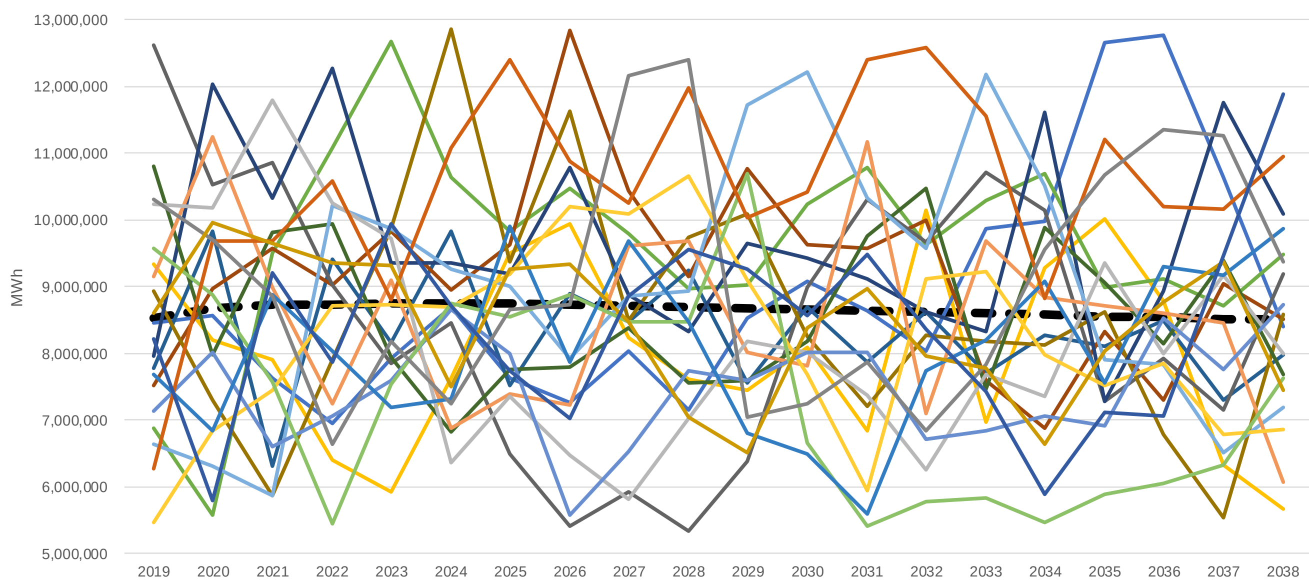


Figure 9.4 Hydro generation sampling (annual MWh)

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.

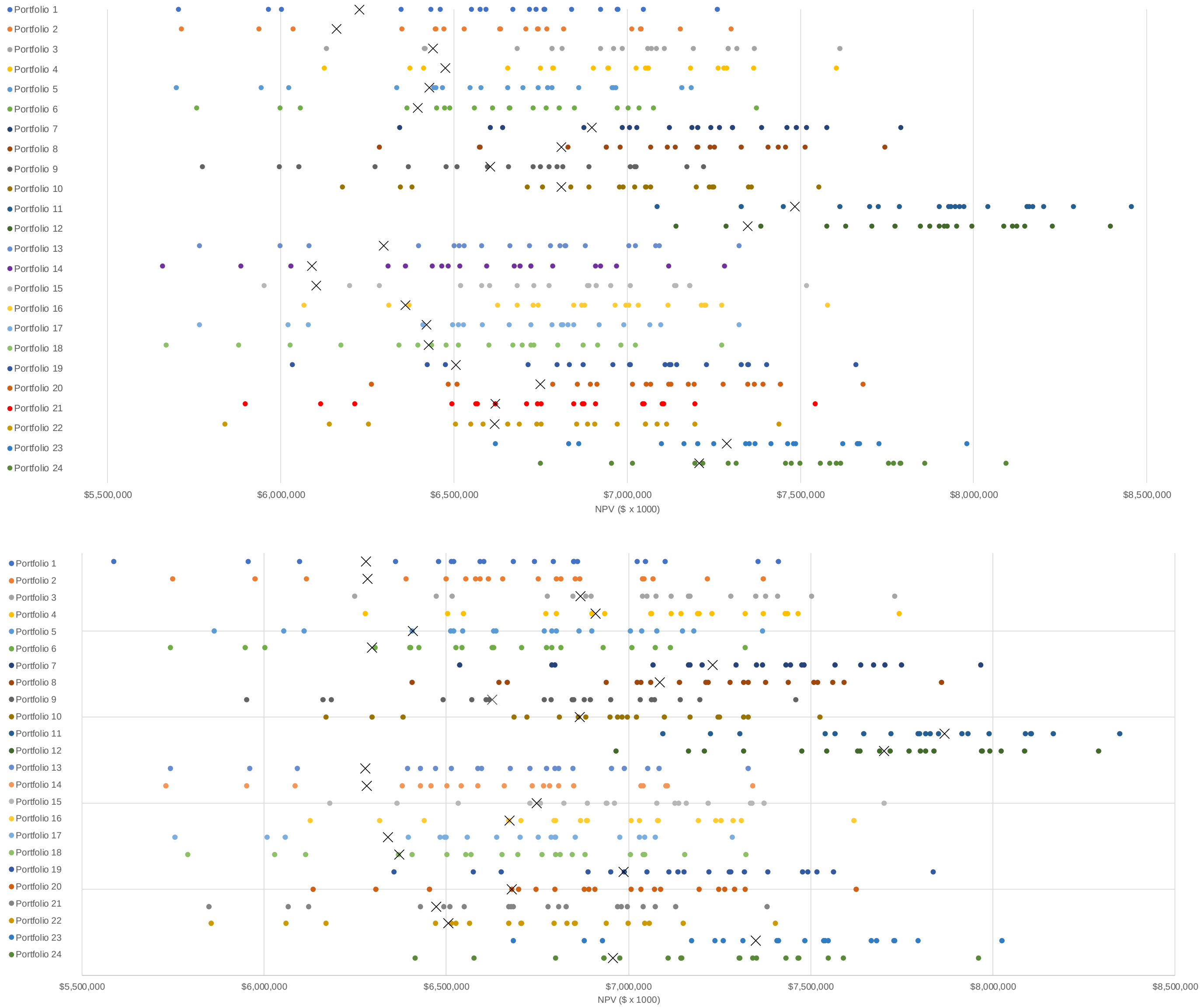
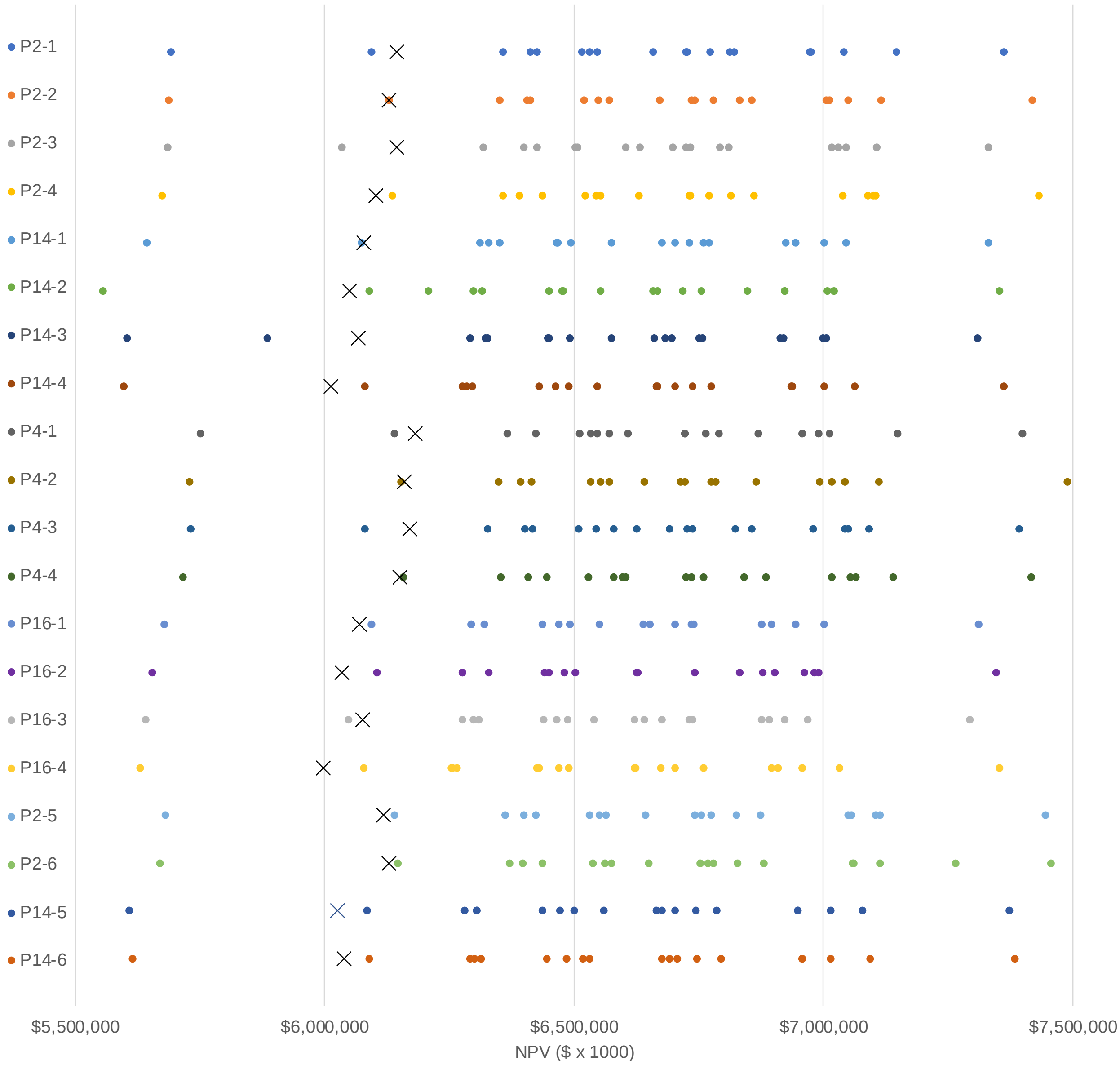


Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2019–2038 ($x 1,000)

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)

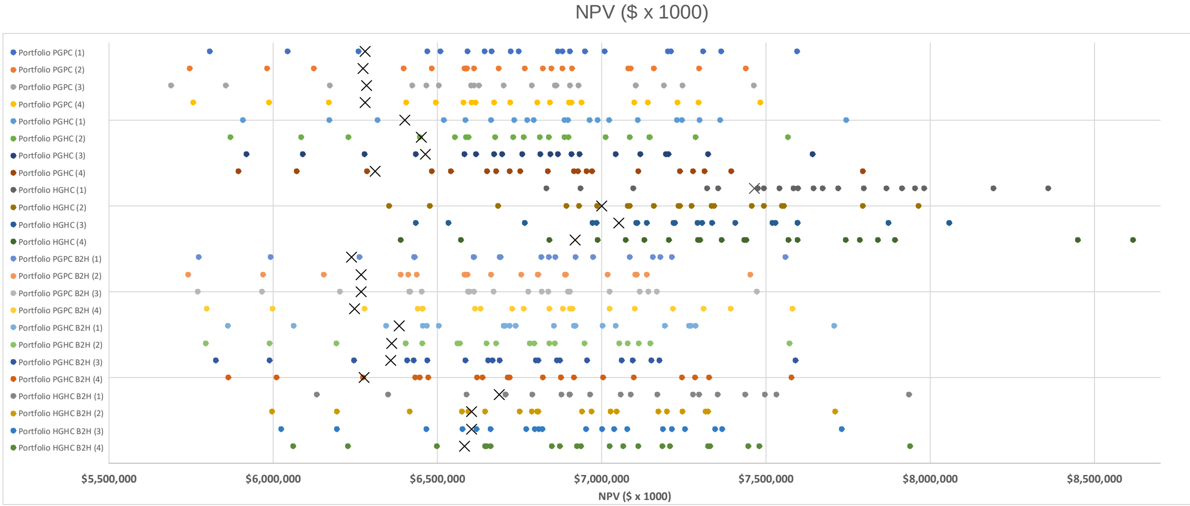
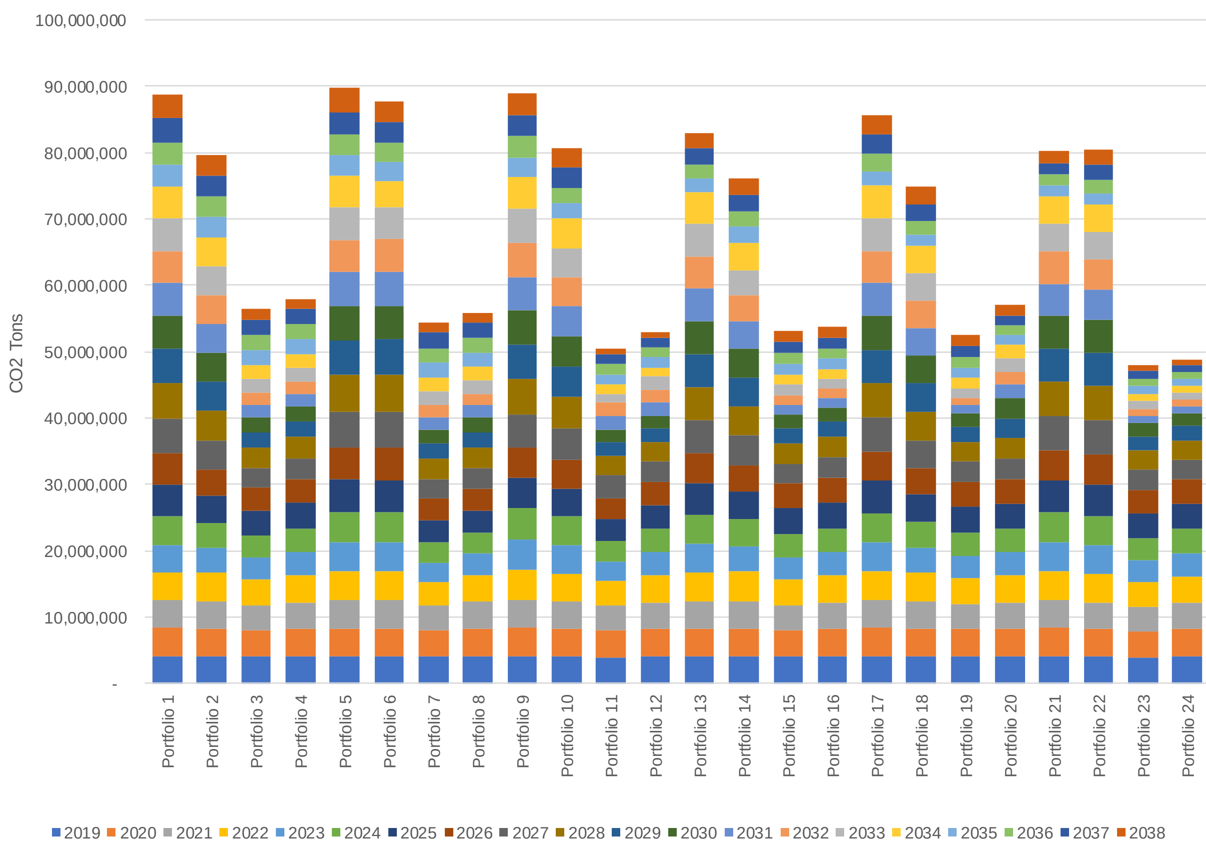

Portfolio PGPC (1)
Portfolio PGPC (2)
Portfolio PGPC (3)
Portfolio PGPC (4)
Portfolio PGHC (1)
Portfolio PGHC (2)
Portfolio PGHC (3)
Portfolio PGHC (4)
Portfolio HGHC (1)
Portfolio HGHC (2)
Portfolio HGHC (3)
Portfolio HGHC (4)
Portfolio PGPC B2H (1)
Portfolio PGPC B2H (2)
Portfolio PGPC B2H (3)
Portfolio 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.



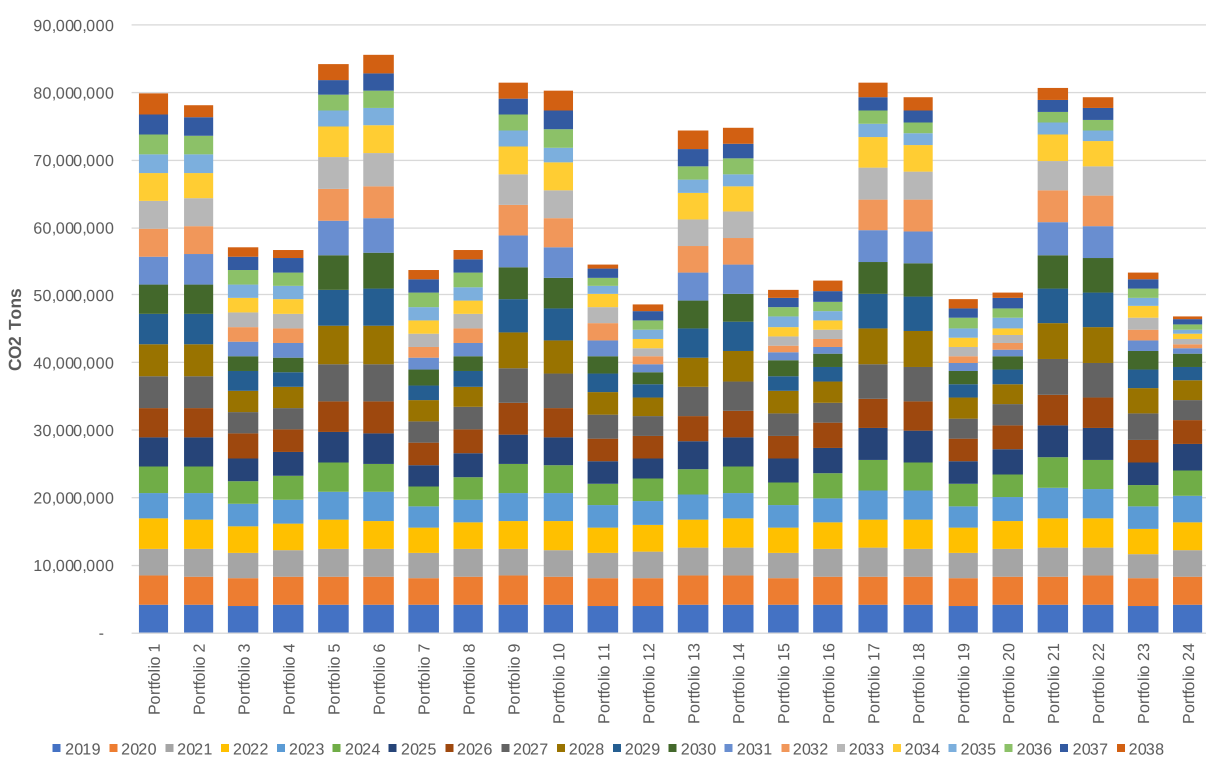
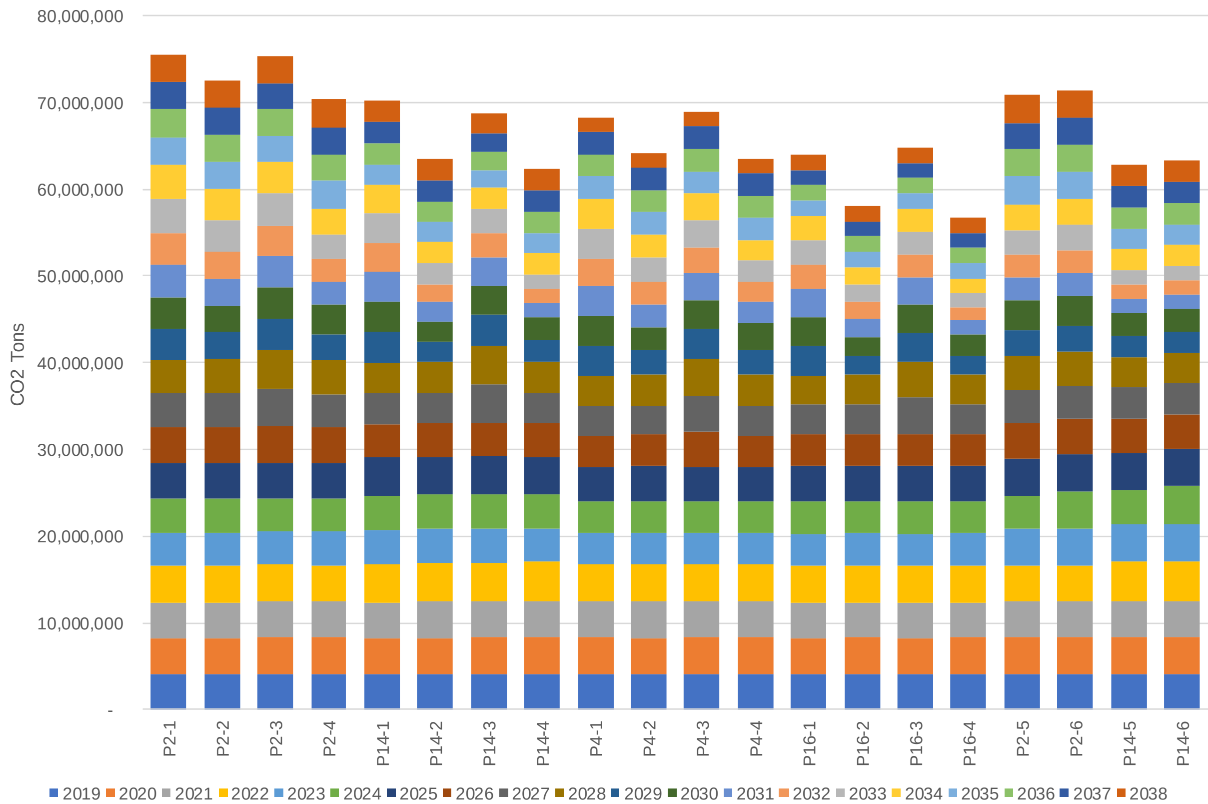


Figure 9.7 Estimated portfolio emissions from 2019–2038



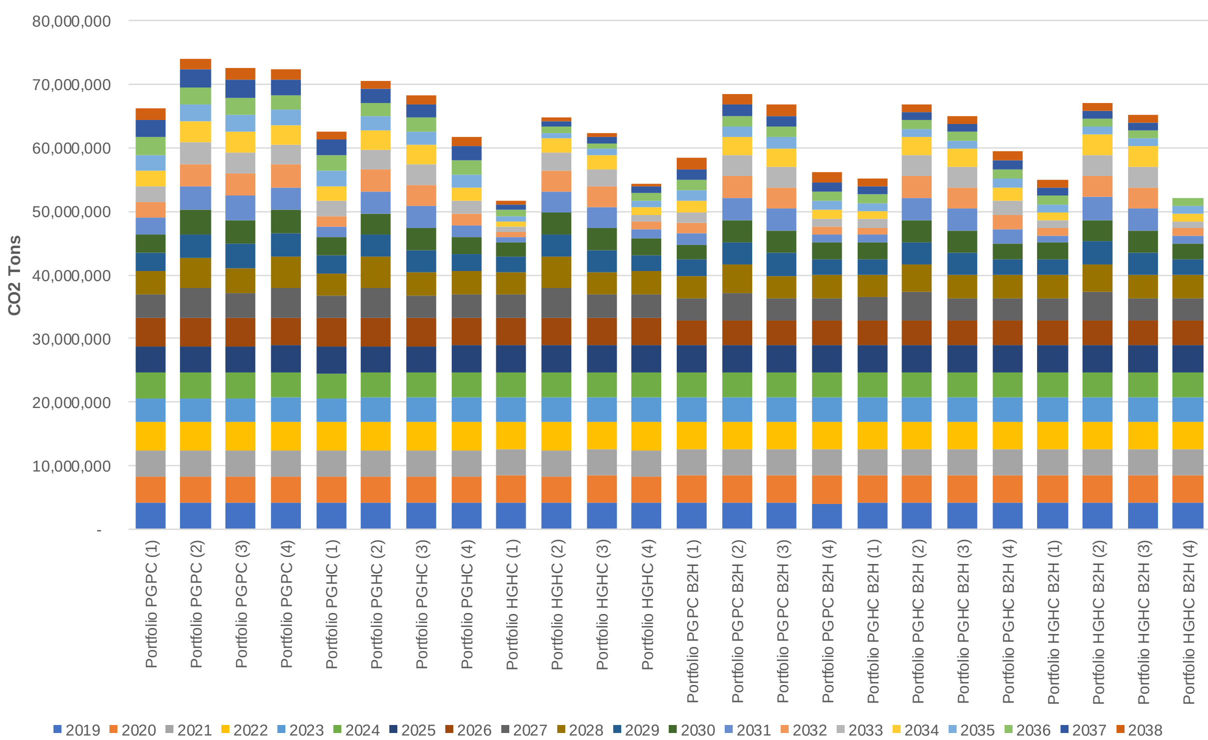


Figure 9.8 Estimated portfolio emissions from 2019–2038—manually built portfolios

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.

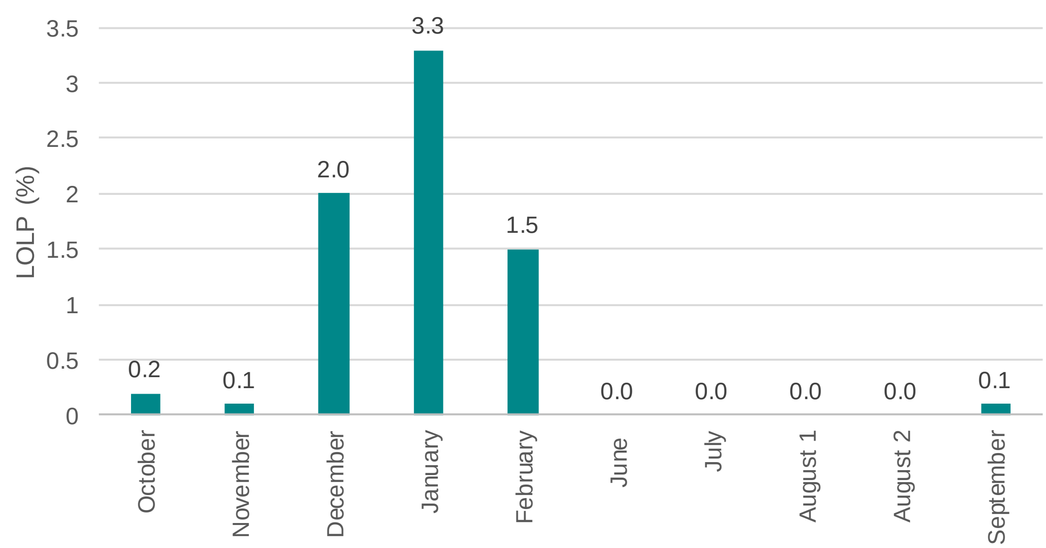


Figure 9.9 LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

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.

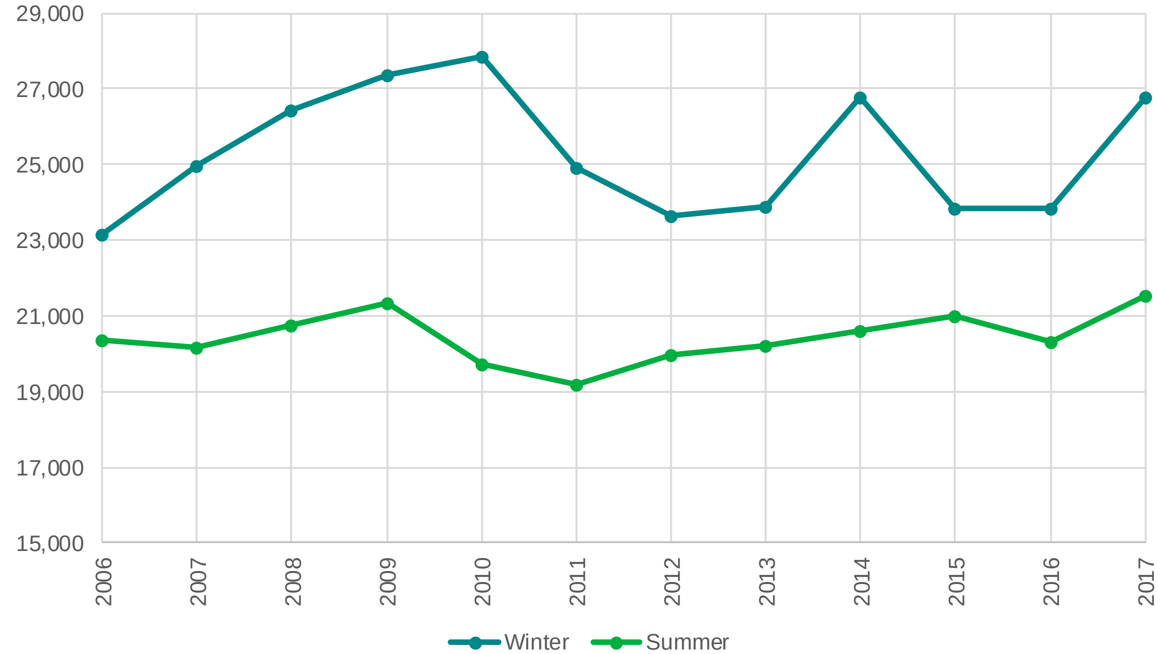


Figure 9.11 Peak coincident load data for most major Washington and Oregon utilities

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.

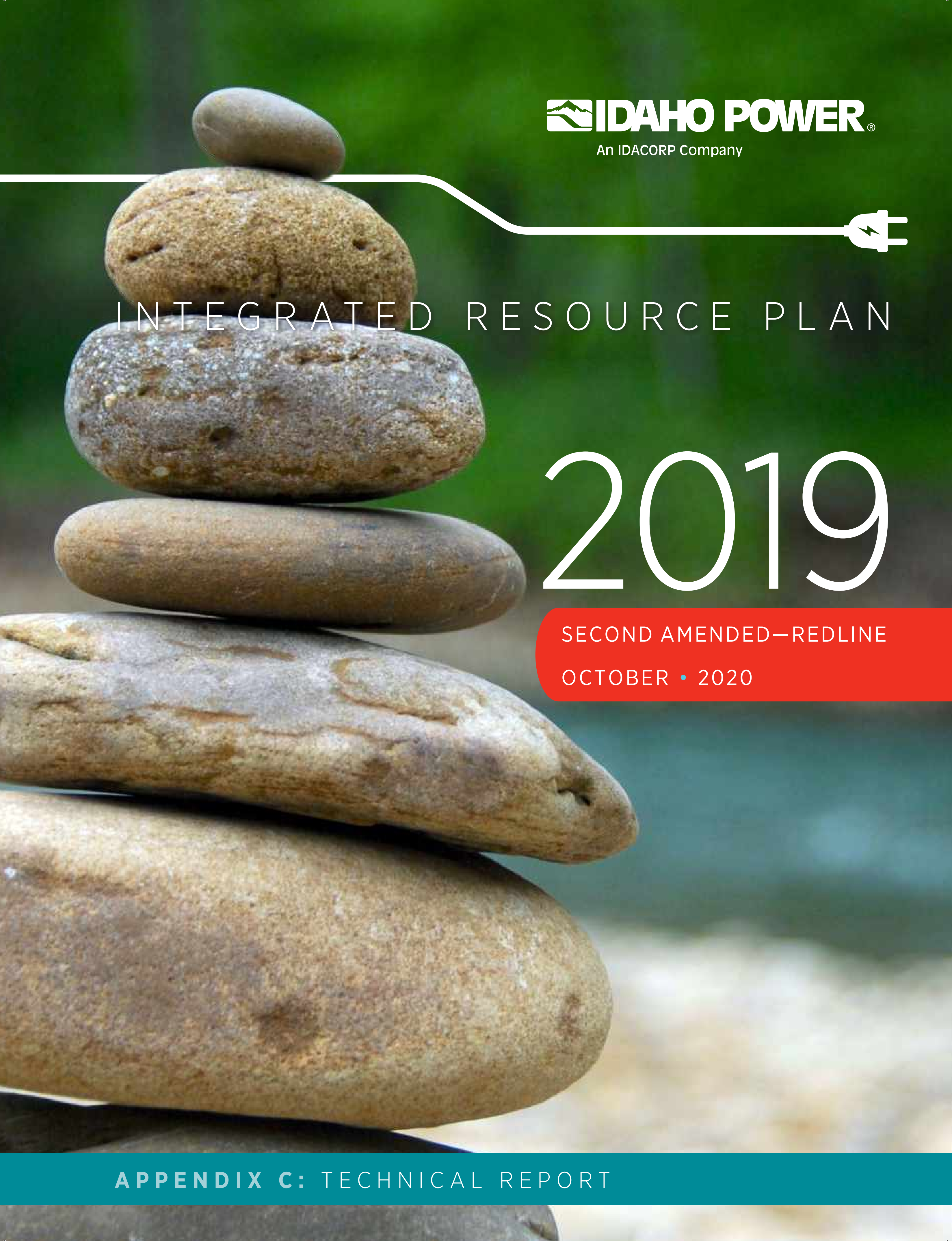
The cost competitiveness of PV solar is another notable theme of the 2019 IRP. The Preferred Portfolio for the *Second Amended 2019 IRP* includes a PPA to purchase output from 120 MW of PV solar projected on-line in December 2022. Idaho Power's IRP analysis indicates this contract allows the cost-competitive 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.



IDAHO POWER
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED—REDLINE

OCTOBER • 2020

APPENDIX C: TECHNICAL REPORT

SAFE HARBOR STATEMENT

TABLE OF CONTENTS

INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2019 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2019 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2018 Annual Report*, and supplemental information on Boardman to Hemingway (B2H) transmission is provided in *Appendix D–B2H Supplement.* The IRP, including the four appendices, was filed with the Idaho and Oregon public utility commissions in June 2019. Amendments to the IRP, *Appendix C—Technical Appendix* and *Appendix D—B2H Supplement* were filed with the Idaho and Oregon public utility commissions in January 2020.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

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Boise, Idaho 83702

208-388-2706

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IRP Advisory Council

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted 10 IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is rewarding, and the IRP is better because of public involvement. Idaho Power and the members of the IRPAC recognize outside perspective is valuable, but also understand that final decisions on the IRP are made by Idaho Power.

Customer Representatives	
Agricultural Representative	Sid Erwin
Boise State University	Barry Burbank
Idaho National Laboratory	Kurt Myers
Micron	Clancy Kelley
St. Luke's Medical	Mark Eriksen
Public-Interest Representatives	
Boise Metro Chamber of Commerce	Ray Stark
Boise State University Energy Policy Institute	Kathleen Araujo
City of Boise	Steve Burgos
Idaho Conservation League	Ben Otto
Idaho Legislature	Representative Robert Anderst
Idaho Office of Energy and Mineral Resources	John Chatburn
Idaho Sierra Club	Mike Heckler
Idaho Technology Council	Jay Larsen
Idaho Water Resource Board	Roger Chase
Northwest Power and Conservation Council	Ben Kujala
Oil and Gas Industry Advisor	David Hawk
Oregon State University—Malheur Experiment Station	Clint Shock
Snake River Alliance	Chad Worth
Regulatory Commission Representatives	
Idaho Public Utilities Commission	Stacey Donohue
Public Utility Commission of Oregon	Nadine Hanhan

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2018	Thursday, September 13	Welcome and opening remarks 2017 IRP Review IRP overview and process road map Carbon Outlook Natural gas forecast
2018	Thursday, October 11	IRP process review Load forecast Streamflow forecast Hydro production forecast Hydro climate change modeling results PURPA forecast and assumptions Natural gas price
2018	Thursday, November 8	Regional transmission overview Boardman to Hemingway transmission update Storage outlook Resource cost assumptions IPC planning criteria capacity, energy, and flexibility—2017 IRP to 2019 IRP Coal unit futures
2018	Thursday, December 13	AURORA model workshop Energy efficiency potential study Regional resource adequacy Solar capacity credit Distributed resources: value to the transmission and distribution system
2019	Thursday, January 10	T&D deferral benefit Demand response Energy imbalance market (EIM) Reserve requirements Capacity expansion modeling update Updated resource cost assumptions
2019	Thursday, March 14	AURORA LTCE portfolio results Sensitivities to planning assumptions Stochastic elements Hells Canyon Complex relicensing Cloud seeding
2019	Thursday, April 11	Idaho Power clean energy goal AURORA results update Qualitative risk assessment Preliminary preferred portfolio recommendation
2019	Thursday, May 9	Loss of load analysis Power system operations: summer readiness IPC sustainability programs 2019 IRP action plan

Meeting Dates		Agenda Items
2019	Thursday, September 18	Review Initial Conclusions Cause for Supplemental Analysis Modeling Updates Next Steps
2019	Friday, December 6	Discount Rate Change Other Updates and Modeling Assumptions Modeling Results 2019 Preferred Portfolio and Action Plan

SALES AND LOAD FORECAST DATA

50th Percentile Annual Forecast Growth Rates

	2019–2024	2019–2029	2019–2038
Sales			
Residential Sales	1.17%	1.15%	1.13%
Commercial Sales	1.17%	1.21%	1.15%
Irrigation Sales	0.78%	0.76%	0.75%
Industrial Sales	1.09%	0.82%	0.56%
Additional Firm Sales	3.68%	2.06%	1.18%
System Sales	1.27%	1.12%	1.00%
Total Sales	1.27%	1.12%	1.00%
Loads			
Residential Load	1.11%	1.15%	1.13%
Commercial Load	1.12%	1.21%	1.14%
Irrigation Load	0.72%	0.76%	0.75%
Industrial Load	1.02%	0.81%	0.55%
Additional Firm Sales	3.68%	2.06%	1.18%
System Load Losses	1.12%	1.10%	1.02%
System Load	1.21%	1.12%	1.00%
Total Load	1.21%	1.12%	1.00%
Peaks			
System Peak	1.35%	1.27%	1.18%
Total Peak	1.35%	1.27%	1.18%
Winter Peak	1.14%	1.03%	0.95%
Summer Peak	1.35%	1.27%	1.18%
Customers			
Residential Customers	2.12%	1.93%	1.68%
Commercial Customers	1.97%	1.80%	1.67%
Irrigation Customers	1.32%	1.28%	1.21%
Industrial Customers	0.53%	0.43%	0.49%

Expected-Case Load Forecast

2019 Monthly Summary[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	831	711	575	502	442	530	649	605	474	487	625	786
Commercial	505	482	443	429	437	482	501	509	463	454	462	513
Irrigation	3	3	8	119	324	624	631	546	316	67	5	3
Industrial	274	280	281	270	274	294	288	296	288	291	283	282
Additional Firm	114	114	108	104	104	95	105	107	111	112	118	120
Loss	147	134	117	119	134	176	190	179	139	116	124	144
System Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Light Load	1,750	1,587	1,406	1,398	1,558	1,991	2,133	1,986	1,616	1,368	1,489	1,712
Heavy Load	1,972	1,826	1,631	1,648	1,837	2,369	2,545	2,429	1,945	1,642	1,720	1,966
Total Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,502	2,277	2,030	2,000	2,675	3,470	3,610	3,354	2,795	2,070	2,277	2,549
System Peak Load (1 hour) 95th Percentile	2,535	2,361	2,075	2,015	2,695	3,511	3,634	3,391	2,812	2,087	2,319	2,636

2020 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	842	695	581	506	445	535	657	613	478	490	629	794
Commercial	513	472	448	434	442	488	508	516	469	459	467	518
Irrigation	3	2	8	120	328	630	638	551	319	68	5	3
Industrial	278	274	284	273	277	298	292	300	292	294	287	287
Additional Firm	117	112	110	106	106	97	106	109	113	114	120	123
Loss	149	131	119	120	135	178	192	181	141	117	125	146
System Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Light Load	1,775	1,553	1,422	1,414	1,575	2,013	2,160	2,011	1,633	1,382	1,504	1,733
Heavy Load	2,000	1,785	1,649	1,667	1,869	2,381	2,577	2,476	1,952	1,658	1,747	1,980
Total Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,522	2,298	2,034	2,017	2,693	3,527	3,659	3,407	2,829	2,087	2,295	2,581
System Peak Load (1 hour) 95th Percentile	2,555	2,382	2,080	2,032	2,713	3,568	3,683	3,444	2,846	2,105	2,337	2,668

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

2021 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	853	730	586	510	448	540	665	620	481	492	633	802
Commercial	518	493	451	439	446	493	513	522	473	462	471	524
Irrigation	3	3	8	121	330	634	642	555	321	68	5	3
Industrial	282	288	288	277	281	302	296	304	296	299	291	289
Additional Firm	121	120	114	110	110	101	111	113	117	119	125	127
Loss	151	137	120	121	136	180	194	183	142	118	126	148
System Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Light Load	1,801	1,631	1,439	1,430	1,592	2,034	2,185	2,035	1,650	1,396	1,520	1,754
Heavy Load	2,038	1,876	1,660	1,685	1,888	2,406	2,607	2,506	1,973	1,686	1,756	2,004
Total Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,555	2,322	2,060	2,032	2,710	3,558	3,707	3,450	2,860	2,105	2,312	2,597
System Peak Load (1 hour) 95th Percentile	2,588	2,406	2,106	2,047	2,730	3,600	3,731	3,487	2,877	2,123	2,354	2,684

2022 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	864	738	590	513	451	545	674	629	486	496	639	812
Commercial	527	500	457	445	452	499	521	530	478	468	477	531
Irrigation	3	3	8	122	333	640	647	560	324	69	5	3
Industrial	284	290	291	280	283	305	299	307	298	301	293	292
Additional Firm	125	124	118	114	114	105	114	117	121	123	129	131
Loss	153	139	121	123	138	182	197	185	144	120	128	149
System Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Light Load	1,826	1,653	1,455	1,446	1,609	2,058	2,214	2,062	1,670	1,413	1,538	1,777
Heavy Load	2,067	1,901	1,679	1,704	1,909	2,434	2,659	2,522	1,997	1,706	1,778	2,031
Total Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,554	2,346	2,080	2,048	2,728	3,609	3,757	3,506	2,897	2,125	2,332	2,625
System Peak Load (1 hour) 95th Percentile	2,617	2,430	2,125	2,063	2,749	3,650	3,782	3,544	2,914	2,143	2,374	2,712

2023 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	878	749	598	519	457	554	687	640	492	501	646	822
Commercial	534	506	462	450	457	505	528	537	483	473	482	537
Irrigation	3	3	8	123	336	645	653	565	326	69	5	3
Industrial	287	293	293	282	286	308	302	310	301	304	296	295
Additional Firm	127	126	120	116	116	107	117	120	124	125	131	134
Loss	156	141	123	124	139	184	199	188	145	121	129	151
System Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Light Load	1,852	1,675	1,472	1,463	1,627	2,083	2,243	2,089	1,689	1,428	1,555	1,799
Heavy Load	2,097	1,927	1,699	1,735	1,919	2,463	2,693	2,555	2,019	1,724	1,797	2,065
Total Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,611	2,369	2,097	2,064	2,747	3,654	3,808	3,559	2,932	2,144	2,350	2,648
System Peak Load (1 hour) 95th Percentile	2,644	2,453	2,143	2,079	2,767	3,696	3,832	3,596	2,949	2,161	2,392	2,735

2024 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	891	734	605	525	462	562	698	650	498	505	652	832
Commercial	540	494	466	455	461	510	534	544	488	477	486	543
Irrigation	3	3	8	124	338	650	658	569	329	70	5	3
Industrial	290	286	296	285	289	311	304	313	304	307	299	297
Additional Firm	138	132	130	124	124	115	124	127	131	134	141	145
Loss	158	138	124	126	141	186	202	190	147	122	131	153
System Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Light Load	1,886	1,646	1,495	1,484	1,650	2,111	2,275	2,119	1,711	1,447	1,578	1,827
Heavy Load	2,125	1,892	1,735	1,750	1,945	2,512	2,715	2,592	2,059	1,736	1,824	2,098
Total Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,650	2,400	2,125	2,087	2,771	3,706	3,863	3,617	2,971	2,167	2,376	2,682
System Peak Load (1 hour) 95th Percentile	2,683	2,484	2,171	2,102	2,791	3,748	3,887	3,655	2,988	2,185	2,418	2,768

2025 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	903	771	611	530	467	569	710	660	503	509	657	840
Commercial	548	519	472	461	467	517	541	551	493	482	492	550
Irrigation	3	3	8	125	341	655	663	573	331	70	5	3
Industrial	292	298	298	287	291	313	307	315	306	309	301	298
Additional Firm	140	139	132	126	125	116	125	128	132	135	143	147
Loss	160	145	125	127	142	188	204	192	148	123	132	155
System Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Light Load	1,911	1,727	1,511	1,499	1,666	2,133	2,302	2,144	1,727	1,460	1,593	1,846
Heavy Load	2,154	1,986	1,753	1,768	1,965	2,538	2,746	2,640	2,065	1,752	1,851	2,109
Total Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,679	2,426	2,144	2,101	2,787	3,753	3,911	3,670	3,003	2,184	2,392	2,705
System Peak Load (1 hour) 95th Percentile	2,711	2,510	2,190	2,116	2,808	3,795	3,935	3,707	3,020	2,201	2,435	2,791

2026 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	914	779	616	534	471	575	719	669	507	511	661	847
Commercial	556	526	477	466	472	523	549	559	499	487	497	556
Irrigation	3	3	8	126	343	660	668	578	334	71	5	3
Industrial	293	300	300	288	292	315	308	317	308	311	303	300
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	162	147	126	128	144	190	207	195	150	124	133	156
System Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Light Load	1,932	1,744	1,523	1,512	1,680	2,152	2,325	2,165	1,741	1,470	1,605	1,862
Heavy Load	2,177	2,006	1,767	1,782	1,993	2,545	2,775	2,667	2,082	1,764	1,865	2,128
Total Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,699	2,443	2,154	2,113	2,801	3,786	3,956	3,712	3,030	2,196	2,404	2,717
System Peak Load (1 hour) 95th Percentile	2,732	2,527	2,200	2,128	2,821	3,827	3,980	3,749	3,047	2,214	2,446	2,804

2027 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	924	787	621	537	474	581	728	677	511	513	664	856
Commercial	564	532	482	472	477	529	556	567	504	492	503	563
Irrigation	3	3	8	127	346	666	674	583	337	72	5	3
Industrial	295	301	302	290	294	317	310	319	310	313	305	302
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	164	148	128	129	145	191	209	197	151	125	134	158
System Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Light Load	1,952	1,761	1,535	1,524	1,693	2,172	2,349	2,187	1,755	1,480	1,616	1,880
Heavy Load	2,210	2,025	1,772	1,796	2,009	2,568	2,803	2,693	2,098	1,787	1,867	2,148
Total Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,721	2,460	2,166	2,124	2,814	3,826	4,001	3,759	3,057	2,208	2,416	2,736
System Peak Load (1 hour) 95th Percentile	2,753	2,544	2,212	2,139	2,835	3,867	4,026	3,796	3,074	2,226	2,458	2,823

2028 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	937	771	627	542	479	588	740	687	516	517	670	866
Commercial	572	520	487	478	483	536	564	575	510	498	508	570
Irrigation	3	3	9	128	349	671	679	587	339	72	5	3
Industrial	297	292	303	292	295	318	312	320	311	314	306	303
Additional Firm	141	136	133	127	126	117	126	129	134	136	145	148
Loss	166	145	129	130	146	193	211	199	152	126	135	160
System Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Light Load	1,976	1,719	1,549	1,537	1,708	2,192	2,375	2,211	1,770	1,491	1,629	1,900
Heavy Load	2,236	1,976	1,788	1,823	2,014	2,593	2,852	2,704	2,116	1,800	1,882	2,181
Total Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,747	2,480	2,183	2,137	2,829	3,874	4,048	3,812	3,087	2,222	2,430	2,761
System Peak Load (1 hour) 95th Percentile	2,780	2,564	2,229	2,152	2,849	3,916	4,073	3,849	3,104	2,240	2,472	2,848

2029 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	952	810	635	548	484	597	752	698	522	522	676	875
Commercial	581	546	493	484	489	543	572	583	516	503	514	578
Irrigation	3	3	9	129	352	676	684	592	342	73	5	3
Industrial	298	304	304	293	297	319	313	322	313	316	307	304
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	168	152	130	132	147	195	214	201	154	127	136	161
System Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Light Load	2,001	1,802	1,564	1,552	1,723	2,214	2,402	2,236	1,786	1,503	1,643	1,918
Heavy Load	2,255	2,072	1,805	1,840	2,032	2,618	2,885	2,734	2,150	1,803	1,898	2,202
Total Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,777	2,505	2,203	2,151	2,844	3,928	4,097	3,869	3,119	2,237	2,444	2,786
System Peak Load (1 hour) 95th Percentile	2,809	2,589	2,249	2,166	2,865	3,970	4,121	3,906	3,136	2,255	2,487	2,873

2030 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	963	820	640	552	488	602	762	706	526	524	680	884
Commercial	590	554	499	491	495	550	580	592	522	509	521	585
Irrigation	3	3	9	130	355	682	690	597	345	73	5	3
Industrial	299	305	305	294	298	320	314	323	314	317	308	305
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	170	154	131	133	149	197	216	203	155	128	137	163
System Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Light Load	2,023	1,820	1,576	1,564	1,737	2,234	2,427	2,258	1,800	1,513	1,654	1,935
Heavy Load	2,280	2,093	1,829	1,844	2,048	2,658	2,895	2,762	2,167	1,815	1,912	2,222
Total Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,799	2,524	2,215	2,163	2,858	3,966	4,143	3,915	3,147	2,250	2,457	2,803
System Peak Load (1 hour) 95th Percentile	2,832	2,608	2,261	2,178	2,878	4,008	4,167	3,953	3,164	2,268	2,499	2,890

2031 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	975	829	645	555	491	608	772	715	530	526	684	892
Commercial	598	561	505	497	501	556	588	600	528	515	526	593
Irrigation	3	3	9	131	357	687	695	601	347	74	5	3
Industrial	300	306	307	295	299	322	315	324	315	318	310	306
Additional Firm	142	141	134	128	127	118	127	130	134	137	145	149
Loss	172	155	132	134	150	199	218	205	156	129	138	164
System Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Light Load	2,046	1,838	1,589	1,576	1,750	2,253	2,451	2,281	1,814	1,523	1,666	1,952
Heavy Load	2,295	2,114	1,843	1,858	2,052	2,681	2,907	2,809	2,155	1,827	1,925	2,220
Total Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,826	2,545	2,233	2,174	2,871	4,019	4,189	3,971	3,174	2,262	2,469	2,828
System Peak Load (1 hour) 95th Percentile	2,859	2,629	2,278	2,189	2,892	4,060	4,213	4,008	3,191	2,280	2,511	2,915

2032 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	987	810	650	559	495	614	782	724	534	529	688	899
Commercial	607	549	510	503	507	563	596	608	534	520	532	599
Irrigation	3	3	9	132	360	692	700	606	350	74	5	3
Industrial	301	297	308	296	300	323	316	325	316	319	311	307
Additional Firm	142	137	134	128	127	118	127	130	135	138	146	150
Loss	174	151	133	135	151	201	221	208	158	130	139	166
System Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Light Load	2,068	1,792	1,601	1,588	1,763	2,271	2,475	2,303	1,827	1,532	1,677	1,967
Heavy Load	2,320	2,071	1,847	1,872	2,079	2,686	2,935	2,836	2,171	1,850	1,927	2,237
Total Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,849	2,559	2,245	2,185	2,884	4,057	4,234	4,017	3,201	2,274	2,480	2,844
System Peak Load (1 hour) 95th Percentile	2,882	2,644	2,290	2,200	2,905	4,099	4,258	4,054	3,218	2,292	2,522	2,930

2033 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	996	846	653	560	496	618	790	731	536	529	690	906
Commercial	615	575	515	509	512	569	603	616	539	525	538	606
Irrigation	3	3	9	133	363	697	706	610	353	75	5	3
Industrial	302	308	309	297	301	324	317	326	317	320	312	308
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	176	158	134	136	152	202	223	209	159	130	140	167
System Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Light Load	2,087	1,872	1,610	1,597	1,774	2,288	2,496	2,323	1,839	1,539	1,685	1,982
Heavy Load	2,352	2,153	1,859	1,883	2,092	2,706	2,979	2,841	2,184	1,859	1,937	2,254
Total Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,870	2,579	2,255	2,195	2,895	4,096	4,277	4,062	3,224	2,283	2,489	2,860
System Peak Load (1 hour) 95th Percentile	2,902	2,664	2,301	2,210	2,916	4,137	4,301	4,099	3,241	2,301	2,532	2,947

2034 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,008	856	659	564	501	625	801	741	541	533	695	916
Commercial	622	581	520	514	517	575	610	623	544	530	542	612
Irrigation	3	3	9	134	365	703	711	615	355	76	5	3
Industrial	303	309	310	298	302	325	318	327	318	321	313	309
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	178	160	135	137	153	204	225	212	160	131	141	169
System Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Light Load	2,108	1,889	1,622	1,609	1,787	2,307	2,522	2,346	1,853	1,549	1,697	1,999
Heavy Load	2,375	2,172	1,871	1,908	2,095	2,729	3,009	2,869	2,201	1,871	1,951	2,284
Total Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,893	2,598	2,269	2,205	2,908	4,142	4,324	4,114	3,252	2,296	2,502	2,882
System Peak Load (1 hour) 95th Percentile	2,926	2,682	2,315	2,220	2,928	4,184	4,348	4,151	3,269	2,314	2,544	2,969

2035 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,022	868	667	571	507	635	816	754	548	538	702	927
Commercial	630	587	525	519	521	581	617	630	549	534	547	618
Irrigation	3	3	9	135	368	708	717	620	358	76	6	3
Industrial	304	310	310	299	303	326	319	328	319	322	313	309
Additional Firm	143	142	135	129	128	119	128	131	136	139	147	150
Loss	180	162	136	138	155	206	227	214	161	132	142	170
System Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Light Load	2,131	1,908	1,635	1,622	1,802	2,329	2,549	2,371	1,868	1,560	1,709	2,017
Heavy Load	2,391	2,194	1,887	1,924	2,113	2,755	3,041	2,899	2,233	1,872	1,965	2,305
Total Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,919	2,619	2,286	2,218	2,923	4,192	4,372	4,168	3,281	2,309	2,515	2,905
System Peak Load (1 hour) 95th Percentile	2,952	2,703	2,331	2,233	2,943	4,233	4,397	4,206	3,298	2,327	2,557	2,992

2036 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,038	851	675	579	514	646	832	768	555	543	709	938
Commercial	637	572	529	524	526	586	624	637	553	538	552	624
Irrigation	3	3	9	136	371	714	722	625	361	77	6	3
Industrial	304	300	311	299	303	326	320	329	319	322	314	310
Additional Firm	144	138	135	129	129	120	129	132	136	139	147	151
Loss	182	158	138	139	156	208	230	216	163	133	143	172
System Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Light Load	2,155	1,862	1,649	1,637	1,817	2,352	2,577	2,396	1,883	1,570	1,722	2,036
Heavy Load	2,418	2,139	1,913	1,929	2,131	2,798	3,057	2,951	2,237	1,884	1,990	2,315
Total Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,948	2,638	2,304	2,232	2,939	4,247	4,422	4,226	3,312	2,322	2,528	2,931
System Peak Load (1 hour) 95th Percentile	2,980	2,722	2,350	2,247	2,959	4,288	4,446	4,264	3,329	2,340	2,570	3,018

2037 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,053	894	684	586	522	657	847	781	563	548	716	949
Commercial	644	599	533	529	531	591	630	644	557	542	556	629
Irrigation	3	3	9	137	374	719	728	630	364	77	6	3
Industrial	305	311	311	300	304	327	320	329	320	323	314	310
Additional Firm	144	143	135	129	129	120	129	132	136	139	147	151
Loss	184	165	139	141	158	210	233	219	164	134	145	173
System Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Light Load	2,179	1,948	1,662	1,650	1,833	2,374	2,605	2,421	1,898	1,581	1,734	2,052
Heavy Load	2,445	2,240	1,928	1,945	2,161	2,807	3,090	2,982	2,255	1,897	2,004	2,334
Total Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,974	2,662	2,320	2,245	2,954	4,295	4,471	4,280	3,341	2,335	2,540	2,951
System Peak Load (1 hour) 95th Percentile	3,006	2,747	2,366	2,260	2,974	4,336	4,495	4,317	3,358	2,353	2,583	3,038

2038 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,068	906	691	593	528	667	862	794	569	553	722	959
Commercial	650	604	537	533	534	596	636	650	561	546	560	633
Irrigation	3	3	9	138	377	725	734	635	367	78	6	4
Industrial	305	311	312	300	304	327	321	330	320	323	315	311
Additional Firm	144	143	135	129	129	120	129	132	137	140	148	151
Loss	186	167	140	142	159	212	235	221	165	135	146	175
System Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Light Load	2,201	1,966	1,675	1,663	1,847	2,395	2,632	2,445	1,912	1,590	1,744	2,069
Heavy Load	2,480	2,261	1,933	1,960	2,178	2,832	3,122	3,011	2,271	1,920	2,005	2,352
Total Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,998	2,682	2,334	2,257	2,968	4,341	4,519	4,332	3,369	2,347	2,552	2,971
System Peak Load (1 hour) 95th Percentile	3,031	2,766	2,380	2,272	2,988	4,382	4,544	4,369	3,386	2,364	2,594	3,058

Annual Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Billed Sales (MWh) 70th Percentile										
Residential	5,437,937	5,493,644	5,547,973	5,608,333	5,688,441	5,763,194	5,834,023	5,890,805	5,944,148	6,014,532
Commercial	4,196,788	4,251,251	4,291,921	4,350,949	4,401,332	4,448,900	4,505,483	4,562,301	4,615,732	4,674,083
Irrigation	2,074,146	2,093,175	2,106,818	2,123,833	2,140,578	2,156,322	2,171,522	2,187,603	2,204,350	2,221,073
Industrial	2,481,792	2,510,977	2,547,534	2,570,263	2,595,285	2,619,587	2,638,463	2,652,628	2,669,207	2,681,291
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Load	15,147,362	15,326,046	15,507,246	15,701,378	15,894,635	16,134,002	16,310,491	16,457,337	16,600,437	16,761,979
Total Load	**15,147,362**	**15,326,046**	**15,507,246**	**15,701,378**	**15,894,635**	**16,134,002**	**16,310,491**	**16,457,337**	**16,600,437**	**16,761,979**
Generation Month Sales (MWh) 70th Percentile										
Residential	5,442,618	5,498,804	5,552,533	5,614,209	5,693,977	5,768,505	5,838,363	5,894,961	5,949,634	6,020,876
Commercial	4,200,298	4,253,908	4,295,719	4,354,214	4,404,424	4,452,555	4,509,159	4,565,769	4,619,509	4,678,039
Irrigation	2,074,158	2,093,183	2,106,828	2,123,843	2,140,588	2,156,331	2,171,532	2,187,613	2,204,360	2,221,083
Industrial	2,484,235	2,514,036	2,549,437	2,572,357	2,597,319	2,621,167	2,639,649	2,654,015	2,670,219	2,682,204
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Total Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Loss	1,290,909	1,305,542	1,319,389	1,335,058	1,351,249	1,368,458	1,383,403	1,396,552	1,409,433	1,424,125
Required Generation	**16,448,918**	**16,642,475**	**16,836,907**	**17,047,681**	**17,256,557**	**17,513,016**	**17,703,106**	**17,862,910**	**18,020,155**	**18,197,327**
Average Load (aMW) 70th Percentile										
Residential	621	626	634	641	650	657	666	673	679	685
Commercial	479	484	490	497	503	507	515	521	527	533
Irrigation	237	238	241	242	244	245	248	250	252	253
Industrial	284	286	291	294	296	298	301	303	305	305
Additional Firm	109	111	116	120	122	130	133	133	133	133
Loss	147	149	151	152	154	156	158	159	161	162
System Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Light Load	1,708	1,723	1,748	1,770	1,792	1,814	1,838	1,855	1,871	1,885
Heavy Load	2,010	2,029	2,058	2,084	2,110	2,134	2,164	2,183	2,203	2,219
Total Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	3,634	3,683	3,731	3,782	3,832	3,887	3,935	3,980	4,026	4,073
Total Peak Load	**3,634**	**3,683**	**3,731**	**3,782**	**3,832**	**3,887**	**3,935**	**3,980**	**4,026**	**4,073**

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Billed Sales (MWh) 70th Percentile										
Residential	6,095,509	6,152,545	6,212,850	6,269,841	6,312,160	6,378,952	6,464,432	6,557,678	6,648,731	6,734,413
Commercial	4,735,240	4,799,479	4,857,014	4,919,215	4,972,567	5,023,928	5,074,557	5,123,093	5,170,831	5,211,986
Irrigation	2,237,536	2,254,044	2,270,422	2,286,620	2,303,006	2,319,804	2,336,631	2,353,973	2,371,564	2,389,219
Industrial	2,692,197	2,700,947	2,713,441	2,720,965	2,731,480	2,739,017	2,745,330	2,750,321	2,754,092	2,758,211
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Total Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Generation Month Sales (MWh) 70th Percentile										
Residential	6,100,167	6,157,528	6,217,678	6,273,685	6,316,791	6,384,855	6,470,892	6,563,965	6,654,615	6,740,060
Commercial	4,739,391	4,803,216	4,861,046	4,922,698	4,975,928	5,027,246	5,077,747	5,126,236	5,173,564	5,214,450
Irrigation	2,237,546	2,254,054	2,270,432	2,286,630	2,303,016	2,319,814	2,336,642	2,353,984	2,371,575	2,389,230
Industrial	2,692,929	2,701,993	2,714,070	2,721,845	2,732,111	2,739,546	2,745,748	2,750,637	2,754,437	2,758,943
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Total Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Loss	1,439,675	1,453,295	1,466,761	1,479,909	1,491,254	1,504,694	1,519,675	1,535,160	1,550,227	1,564,294
Required Generation	**18,382,709**	**18,546,087**	**18,707,987**	**18,864,766**	**19,002,100**	**19,162,154**	**19,338,704**	**19,520,980**	**19,697,417**	**19,862,977**
Average Load (aMW) 70th Percentile										
Residential	696	703	710	714	721	729	739	747	760	769
Commercial	541	548	555	560	568	574	580	584	591	595
Irrigation	255	257	259	260	263	265	267	268	271	273
Industrial	307	308	310	310	312	313	313	313	314	315
Additional Firm	134	134	134	134	135	135	136	136	136	137
Loss	164	166	167	168	170	172	173	175	177	179
System Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Light Load	1,909	1,926	1,943	1,954	1,973	1,990	2,008	2,022	2,046	2,063
Heavy Load	2,247	2,267	2,281	2,293	2,316	2,336	2,357	2,373	2,401	2,421
Total Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544
Total Peak Load	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544

DEMAND-SIDE RESOURCE DATA

DSM Financial Assumptions

Avoided Levelized Capacity Costs	
Reciprocating Internal Combustion Engine (RICE)	$121.19/kW-year
Financial Assumptions	
Discount rate (weighted average cost of capital)	7.12%
Financial escalation factor	2.20%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Avoided Cost Averages ($/MWh except where noted)

Year	Summer On-Peak[1]	Summer Mid-Peak	Summer Off-Peak	Non-Summer Mid-Peak	Non-Summer Off-Peak	Annual Average[2]	Annual T&D On-Peak Deferral Value ($/kW-year)
2019	$44.25	$30.93	$27.15	$27.62	$23.11	$42.64	$6.52
2020	$47.17	$30.09	$26.65	$27.89	$23.04	$42.48	$4.10
2021	$50.02	$32.14	$28.38	$28.85	$24.22	$43.84	$4.10
2022	$52.88	$32.97	$28.97	$29.62	$25.35	$44.84	$4.10
2023	$54.91	$34.45	$29.94	$30.49	$26.42	$45.90	$3.99
2024	$56.78	$36.59	$32.11	$32.88	$27.97	$47.87	$3.99
2025	$58.50	$38.44	$33.77	$34.49	$29.61	$49.57	$3.84
2026	$60.06	$36.45	$29.23	$35.82	$28.36	$49.27	$3.94
2027	$61.46	$38.80	$32.47	$38.86	$31.27	$52.10	$4.10
2028	$62.79	$42.29	$35.52	$40.54	$33.90	$54.32	$4.22
2029	$64.09	$43.66	$39.51	$42.43	$36.96	$56.75	$4.28
2030	$65.39	$44.72	$38.76	$42.36	$36.83	$56.79	$4.22
2031	$66.67	$47.61	$42.11	$45.57	$39.65	$59.75	$4.28
2032	$67.95	$48.68	$43.86	$47.19	$41.24	$61.26	$4.28
2033	$69.24	$49.94	$44.90	$48.55	$42.85	$62.70	$4.28
2034	$70.55	$51.39	$46.69	$50.04	$44.42	$64.01	$2.49
2035	$71.90	$52.98	$47.92	$52.00	$45.97	$65.72	$2.67
2036	$73.27	$55.74	$49.99	$54.04	$47.63	$67.63	$2.59
2037	$74.88	$56.50	$52.01	$56.40	$49.00	$69.35	$1.40
2038	$76.53	$55.18	$52.09	$55.50	$49.35	$69.04	$1.49

[1] Estimated average annual variable operations and management costs of a 111 MW-capacity RICE unit.

[2] Annual average across all hours includes avoided capacity value of $121.19 kW-year from a 111 MW RICE unit applied across Summer On-Peak hours.

Bundle Amounts

Cumulative Achievable Potential (aMW)

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	1	3	4	6	7	9	11	13	15	17
10-20th Percentile	3	3	5	6	8	10	11	13	15	17
20-30th Percentile	3	5	7	9	12	14	16	18	20	22
30-40th Percentile	1	3	5	6	8	10	12	14	16	18
40-50th Percentile	2	3	5	6	8	10	11	13	14	16
50-60th Percentile	1	3	4	6	7	8	10	11	13	14
60-70th Percentile	2	4	6	9	11	13	15	17	19	21
70-80th Percentile	3	6	10	13	16	19	21	23	25	27
80-90th Percentile	2	5	7	10	13	16	19	21	24	26
90-100th Percentile	2	4	6	8	11	14	16	19	22	24
High Cost	2	5	8	11	14	17	20	23	25	27
Total	**24**	**44**	**67**	**90**	**115**	**140**	**163**	**186**	**208**	**228**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
0-10th Percentile	19	21	23	25	27	29	30	31	32	33
10-20th Percentile	19	20	22	25	27	28	30	31	32	33
20-30th Percentile	23	25	26	28	29	31	32	32	33	34
30-40th Percentile	20	22	24	25	27	28	30	31	32	33
40-50th Percentile	17	19	21	23	25	27	28	30	32	34
50-60th Percentile	15	17	19	20	22	24	26	29	31	33
60-70th Percentile	22	24	25	26	28	29	30	31	32	33
70-80th Percentile	28	29	30	31	32	32	33	33	33	34
80-90th Percentile	28	29	30	31	31	32	32	33	33	34
90-100th Percentile	26	28	29	30	30	31	32	32	33	33
High Cost	29	31	33	34	35	37	38	39	40	41
Total	**247**	**265**	**282**	**298**	**314**	**327**	**340**	**352**	**364**	**375**

Bundle Costs

Savings-Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	-$115	-$111	-$106	-$102	-$99	-$97	-$108	-$108	-$105	-$104
10-20th Percentile	-$5	-$8	-$7	-$5	-$5	-$5	-$15	-$15	-$15	-$15
20-30th Percentile	$14	$14	$14	$14	$14	$15	$14	$14	$15	$15
30-40th Percentile	$38	$38	$38	$38	$38	$38	$32	$32	$32	$32
40-50th Percentile	$42	$42	$42	$42	$41	$42	$40	$40	$39	$39
50-60th Percentile	$56	$56	$55	$55	$55	$55	$56	$55	$55	$54
60-70th Percentile	$68	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$138	$138	$139	$139	$139	$139	$136	$133	$130	$127
80-90th Percentile	$133	$135	$136	$137	$138	$137	$135	$134	$133	$132
90-100th Percentile	$192	$190	$189	$188	$188	$188	$187	$187	$187	$188
High Cost	$2,145	$2,144	$2,121	$2,094	$2,063	$2,001	$1,936	$1,876	$1,866	$1,906
Total	**$277**	**$312**	**$322**	**$330**	**$331**	**$325**	**$299**	**$285**	**$278**	**$271**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20-Year Average
0-10th Percentile	-$103	-$105	-$104	-$103	-$103	-$91	-$92	-$89	-$83	-$90	-$102
10-20th Percentile	-$15	-$27	-$27	-$27	-$27	-$28	-$29	-$29	-$30	-$30	-$18
20-30th Percentile	$15	$15	$15	$15	$15	$15	$15	$13	$13	$12	$14
30-40th Percentile	$32	$27	$27	$27	$26	$26	$26	$27	$27	$27	$32
40-50th Percentile	$38	$35	$35	$34	$34	$34	$34	$34	$34	$34	$38
50-60th Percentile	$52	$45	$44	$43	$42	$42	$42	$40	$40	$40	$48
60-70th Percentile	$70	$69	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$123	$120	$116	$112	$109	$107	$76	$73	$71	$69	$131
80-90th Percentile	$131	$130	$128	$126	$124	$121	$110	$111	$111	$112	$133
90-100th Percentile	$189	$190	$192	$194	$195	$196	$195	$195	$195	$195	$189
High Cost	$2,025	$2,204	$2,424	$2,653	$2,858	$3,049	$3,260	$3,261	$3,366	$3,463	$2,235
Total	**$267**	**$257**	**$257**	**$257**	**$259**	**$292**	**$296**	**$329**	**$359**	**$384**	$290

SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.10%
Preferred	0.00%
Common	49.90%
Total	**100.00%**
Cost	
Debt	5.73%
Preferred	0.00%
Common	10.00%
Average Weighted Cost	7.86%

Financial Assumptions and Factors	
Plant operating (book) life	Expected Life of the Asset
Discount rate (weighted average cost of capital[1])	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
Emission adder excalation rate	3.00%
General O&M escalation rate	2.20%
Annual property tax rate (% of investment)	0.49%
B2H annual property tax rate (% of investment)	0.55%
Property tax escalation rate	3.00%
B2H property tax escalation rate	1.67%
Annual insurance premiums (% of investment)	0.03~~1~~%
B2H annual insurance premiums (% of investment)	0.03%
Insurance escalation rate	2.00%
B2H insurance escalation rate	2.00%
AFUDC rate (annual)	7.65%

[1] Incorporates tax effects.

Fuel Forecast Base Case (Nominal, $ per MMBTU)

Year	Generic Coal	Nuclear
2019	$2.40	
2020	$2.49	
2021	$2.55	
2022	$2.62	
2023	$2.68	$0.62
2024	$2.74	$0.63
2025	$2.80	$0.65
2026	$2.86	$0.66
2027	$2.91	$0.68
2028	$2.96	$0.69
2029	$3.01	$0.71
2030	$3.08	$0.72
2031	$3.15	$0.74
2032	$3.21	$0.75
2033	$3.30	$0.77
2034	$3.39	$0.79
2035	$3.46	$0.81
2036	$3.57	$0.82
2037	$3.65	$0.84
2038	$3.75	$0.86

Cost Inputs and Operating Assumptions (Costs in 2019$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital ($/kW)	Total Capital ($/kW)	Total Investment ($/kW)[2]	Fixed O&M ($/kW-mth)[3]	Variable O&M ($/MWh)	Integration ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (years)
Biomass (35 MW)	35	$3,577	$133	$3,710	$4,614	$3.13	$16.68	$0.00	0	30
Boardman to Hemingway (350 MW)	350	$0	$894	$894	$894	$0.42	$0.00	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,096	$102	$1,198	$1,401	$0.92	$2.90	$0.00	6,420	30
Geothermal (30 MW)	30	$6,014	$150	$6,164	$7,904	$15.05	$0.00	$0.00	0	25
Reciprocating Gas Engine (111.1 MW)	111	$885	$117	$1,002	$1,067	$1.00	$5.42	$0.00	8,300	40
Reciprocating Gas Engine (55.5 MW)	56	$994	$117	$1,111	$1,183	$1.00	$5.42	$0.00	8,300	40
SCCT—Frame F Class (170 MW)	170	$932	$122	$1,054	$1,122	$1.07	$7.48	$0.00	9,720	35
Small Modular Nuclear (60 MW)	60	$4,292	$165	$4,457	$6,722	$0.70	$2.09	$0.00	11,493	40
Solar PV—Residential Rooftop (.005 MW)	0.005	$3,590	$0	$3,590	$3,730	$1.79	$0.00	$0.00	0	25
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	40	$1,402	$150	$1,552	$1,613	$1.02	$0.00	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (10 MW)	50	$1,658	$150	$1,808	$1,879	$0.97	$0.49	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (20 MW)	60	$1,829	$150	$1,979	$2,056	$0.94	$0.81	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (30 MW)	70	$1,950	$150	$2,100	$2,183	$0.92	$1.03	$0.63	0	30
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	0.5	$1,823	-$62	$1,761	$1,830	$0.93	$0.00	$0.00	0	25
Storage—4-Hr Li Battery (5 MW)	5	$1,973	$52	$2,025	$2,064	$0.78	$2.47	$0.00	0	20
Storage—8-Hr Li Battery (5 MW)	5	$3,277	$52	$3,329	$3,393	$0.78	$2.47	$0.00	0	10
Storage—Pumped-Hydro (500 MW)	500	$1,800	$191	$1,991	$2,315	$0.33	$0.00	$0.00	0	75
Wind ID (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25
Wind WY (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Levelized Cost of Energy (Costs in 2023$, $/MWh)[1]

At stated capacity factors

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[2]	Fuel	Wholesale Energy	Net of Tax Credit/ Integration	Total Cost per MWh	Capacity Factor
Biomass (35 MW)[3]	$65	$36	$0	$0	$0	$101	85%
Boardman to Hemingway (350 MW)	$26	$3	$0	$40	-$8	$62	33%
CCCT (1x1) F Class (300 MW)	$28	$9	$34	$0	$0	$71	60%
Geothermal (30 MW)	$103	$41	$0	$0	$0	$144	88%
Reciprocating Gas Engine (111.1 MW)	$79	$29	$46	$0	$0	$155	15%
Reciprocating Gas Engine (55.5 MW)	$88	$30	$46	$0	$0	$164	15%
SCCT—Frame F Class (170 MW)	$256	$76	$53	$0	$0	$386	5%
Small Modular Nuclear (60 MW)	$83	$28	$10	$0	$0	$121	90%
Solar PV—Residential Rooftop (.005 MW)	$154	$25	$0	$0	$0	$180	21%
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$60	$12	$0	$0	-$5	$67	26%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$82	$16	$0	$0	-$7	$90	22%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$109	$20	$0	$0	-$10	$120	18%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$139	$25	$0	$0	-$13	$152	15%
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$71	$12	$0	$0	-$6	$77	26%
Storage—4-Hr Li Battery (5 MW)[3]	$201	$30	$0	$0	$0	$232	11%
Storage—8-Hr Li Battery (5 MW)[3]	$231	$19	$0	$0	$0	$250	23%
Storage—Pumped-Hydro (500 MW)[3]	$153	$21	$0	$0	$0	$175	16%
Wind ID (100 MW)	$60	$28	$0	$0	$26	$114	35%
Wind WY (100 MW)	$47	$22	$0	$0	$26	$94	45%

[1] Levelized costing in 2023$ assuming 2023 online date. Common online date five years into IRP planning window allows levelized costing to capture projected trends in resource costs.
[2] Non-Fuel O&M includes fixed and variable costs, property taxes.
[3] Fuel costs not included for biomass resource. Storage resources do not include costs of recharge energy. As noted in IRP, levelized costing for storage resources driven overwhelmingly by fixed costs.

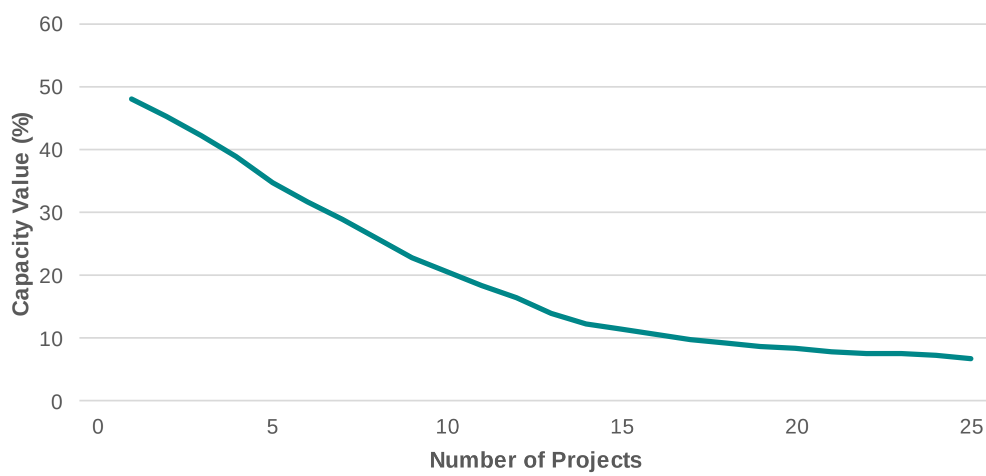
Levelized Capacity (fixed) Cost per kW/Month (Costs in 2019$)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Tax Credit	Total Cost per kW
Biomass (35 MW)	$37	$7	$0	$44
Boardman to Hemingway (350 MW)	$6	$1	-$2	$5
CCCT (1x1) F Class (300 MW)	$11	$2	$0	$13
Geothermal (30 MW)	$61	$24	$0	$85
Reciprocating Gas Engine (111.1 MW)	$8	$2	$0	$10
Reciprocating Gas Engine (55.5 MW)	$9	$2	$0	$11
SCCT—Frame F Class (170 MW)	$9	$2	$0	$11
Small Modular Nuclear (60 MW)	$50	$6	$0	$56
Solar PV—Residential Rooftop (.005 MW)	$29	$~~3~~4	$0	$33~~1~~
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$12	$2	-$1	$13
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$14	$3	-$1	$15
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$15	$3	-$1	$16
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$16	$3	-$1	$17
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$14	$2	-$1	$15
Storage—4-Hr Li Battery (5 MW)	$17	$2	$0	$20
Storage—8-Hr Li Battery (5 MW)	$43	$3	$0	$46
Storage—Pumped-Hydro (500 MW)	$16	$2	$0	$19
Wind ID (100 MW)	$1~~4~~5	$7	$0	$22~~1~~
Wind WY (100 MW)	$13~~5~~	$7	$0	$20~~2~~

Solar Peak-Hour Capacity Credit (contribution to peak)

	Project MWAC	Total Installed MWAC ABV Current	Project Capacity Value (% Proj MWAC)	Project Capacity Value (MWAC)
Project 1	40	40	45.4%	18.1
Project 2	40	80	42.1%	16.9
Project 3	40	120	38.8%	15.5
Project 4	40	160	34.7%	13.9
Project 5	40	200	31.6%	12.7
Project 6	40	240	28.8%	11.5
Project 7	40	280	25.9%	10.4
Project 8	40	320	22.8%	9.1
Project 9	40	360	20.5%	8.2
Project 10	40	400	18.3%	7.3
Project 11	40	440	16.4%	6.5
Project 12	40	480	14.0%	5.6
Project 13	40	520	12.4%	5.0
Project 14	40	560	11.6%	4.6
Project 15	40	600	10.6%	4.2
Project 16	40	640	9.9%	4.0
Project 17	40	680	9.4%	3.7
Project 18	40	720	8.7%	3.5
Project 19	40	760	8.5%	3.4
Project 20	40	800	8.0%	3.2
Project 21	40	840	7.7%	3.1
Project 22	40	880	7.7%	3.1
Project 23	40	920	7.2%	2.9
Project 24	40	960	6.9%	2.8

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



PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio:

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2019	Valmy Unit 1	(127)	(127)[1]
2020	Boardman	(58)	(58)[2]
2022	Bridger Unit	(177)	(177)
2022	Solar	120	41
2025	Valmy Unit 2	(133)	(133)[1]
2026	B2H	500 (Apr–Sep)/ 200 (Oct–Mar)	500
2026	Bridger Unit	(180)	(180)
2028	Bridger Unit	(174)	(174)
2030	Solar	40	14
2030	Battery Storage	30	30
2030	Demand Response	5	5
2031	CCCT	300	300
2032	Demand Response	5	5
2033	Demand Response	5	5
2034	Solar	40	13
2034	Battery Storage	20	10
2034	Demand Response	5	5
2035	Solar	80	22
2035	Battery Storage	20	20
2035	Demand Response	5	5
2036	Solar	120	31
2036	Battery Storage	10	20
2036	Demand Response	5	5
2037	Reciprocating Engines	55.5	55.5
2037	Demand Response	5	5
2038	Reciprocating Engines	55.5	55.5
2037	Demand Response	5	5

1. Exit from North Valmy units not considered to affect capacity deficiency period because of IRP's assumed peak-hour wholesale electric market imports across existing north Valmy transmission line.
2. Ceased coal-fired operations at Boardman in 2020 considered a committed resource action.

2. Deficiency period start

   First capacity deficit = (42) MW July 2029

3. Intermittent generation integration costs

   Idaho—Schedule 87[2]

   Oregon—Schedule 85[3]

Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2019	4.84
2020	5.04
2021	5.31
2022	5.33
2023	5.44
2024	5.73
2025	5.75
2026	5.85
2027	5.89
2028	6.16
2029	6.21
2030	6.48
2031	6.53
2032	6.94
2033	7.07
2034	7.17
2035	7.55
2036	7.66
2037	8.04
2038	8.04

[2] idahopower.com/about-us/company-information/rates-and-regulatory/retail-tariffs-idaho/

[3] idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/

EXISTING RESOURCE DATA

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects Status as of December 31, 2019.

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Hydro Projects							
Arena Drop	0.45	Sep-2010	Sep-2030	Littlewood/Arkoosh	0.87	Aug-1986	Aug-2021
Baker City Hydro	0.24	Sep-2015	Sep-2030	Low Line Canal	7.97	May-1985	May-2020
Barber Dam	3.70	Apr-1989	Apr-2024	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Birch Creek	0.05	Nov-1984	Nov-2039	Lowline #2	2.79	Apr-1988	Apr-2023
Black Canyon #3	0.13	Apr-2019	Apr-2039	Magic Reservoir	9.07	Jun-1989	Jun-2024
Black Canyon Bliss Hydro	0.03	Nov-2014	Oct-2035	Malad River	1.17	May-2019	May-2039
Blind Canyon	1.63	Dec-2014	Dec-2034	Marco Ranches	1.20	Aug-1985	Aug-2020
Box Canyon	0.30	Feb-2019	Feb-2039	MC6 Hydro	2.10	Jul-2019	Jul-2039
Briggs Creek	0.60	Oct-1985	Oct-2020	Mile 28	1.50	Jun-1994	Jun-2029
Bypass	9.96	Jun-1988	Jun-2023	Mitchell Butte	2.09	May-1989	Dec-2033
Canyon Springs	0.11	Jan-2019	Jan-2039	Mora Drop Small Hydro	1.85	Sep-2006	Sep-2026
Cedar Draw	1.55	Jun-1984	Jun-2039	Mud Creek/S&S	0.52	Feb-2017	Feb-2037
Clear Springs Trout	0.56	Nov-2018	Nov-2038	Mud Creek/White	0.21	Jan-1986	Jan-2021
Crystal Springs	2.44	Apr-1986	Apr-2021	North Gooding Main	1.30	Oct-2016	Oct-2036
Curry Cattle Company	0.25	Jun-2018	Jun-2033	Owyhee Dam CSPP	5.00	Aug-1985	May-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pigeon Cove	1.89	Oct-1984	Nov-2039
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #1	0.10	May-2015	May-2020
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3	0.20	May-2015	May-2020
Fall River	9.10	Aug-1993	Aug-2028	Reynolds Irrigation	0.26	May-1986	May-2021
Fargo Drop Hydroelectric	1.27	Apr-2013	Apr-2033	Rock Creek #1	2.17	Jan-2018	Jan-2038
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #2	1.90	Apr-1989	Apr-2024
Fisheries Dev.	0.26	Jul-1990	As Delivered	Sagebrush	0.43	Sep-1985	Sep-2020
Geo-Bon #2	0.93	Nov-1986	Nov-2021	Sahko Hydro	0.50	Feb-2011	Feb-2021
Hailey CSPP	0.06	Jun-1985	Jun-2020	Schaffner	0.53	Aug-1986	Aug-2021
Hazelton A	8.10	Mar-2011	Mar-2026	Shingle Creek	0.22	Aug-2017	Aug-2022
Hazelton B	7.60	May-1993	May-2028	Shoshone #2	0.58	May-1996	May-2031
Head of U Canal Project	1.28	May-2015	Jun-2035	Shoshone CSPP	0.36	Feb-2017	Feb-2037
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snake River Pottery	0.07	Nov-1984	Dec-2027
Jim Knight	0.34	Jun-1985	Jun-2020	Snedigar	0.54	Jan-1985	Jan-2040
Koyle Small Hydro	1.25	Apr-2019	Apr-2039	Tiber Dam	7.50	Jun-2004	Jun-2024
Lateral # 10	2.06	May-1985	May-2020	Trout-Co	0.24	Dec-1986	Dec-2021
Lemoyne	0.08	Jun-1985	Jun-2020	Tunnel #1	7.00	Jun-1993	Feb-2035
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035	White Water Ranch	0.16	Aug-1985	Aug-2020
Little Wood River Res	2.85	Feb-1985	Feb-2020	Wilson Lake Hydro	8.40	May-1993	May-2028

Total Hydro Nameplate Rating 148.85 MW

Thermal Projects			
Simplot Pocatello Cogen	15.90	Mar-2019	Mar-2022
TASCO—Nampa Natural Gas	2	Sep-2003	As Delivered
TASCO—Twin Falls Natural Gas	3	Aug-2001	As Delivered
Total Thermal Nameplate Rating 20.90 MW			

		Contract				Contract	
Project	**MW**	**On-line Date**	**End Date**	**Project**	**MW**	**On-line Date**	**End Date**
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2010	Aug-2020	Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027
Bannock County Landfill	3.20	May-2014	May-2034	Pocatello Waste	0.46	Dec-1985	Dec-2020
Bettencourt Dry Creek	2.25	May-2010	May-2020	Rock Creek Dairy	4.00	Aug-2012	Aug-2027
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	SISW LFGE	5.00	Oct-2018	Estimated
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	6.25	Jun-2018	Jun-2038
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029				
Total Biomass Nameplate Rating 35.70 MW							

Solar Projects							
American Falls Solar II, LLC	20.00	Mar-2017	Mar-2037	Murphy Flat Power, LLC	20.00	Mar-2017	Mar-2037
American Falls Solar, LLC	20.00	Mar-2017	Mar-2037	Ontario Solar Center	3.00	Dec-2019	Estimated
Baker Solar Center	15.00	Dec-2019	Estimated	Open Range Solar Center, LLC	10.00	Mar-2017	Mar-2037
Brush Solar	2.75	Oct-2019	Estimated	Orchard Ranch Solar, LLC	20.00	Oct-2016	Oct-2036
Grand View PV Solar Two	80.00	Dec-2016	Dec-2036	Railroad Solar Center, LLC	4.50	Dec-2016	Dec-2036
Grove Solar Center, LLC	6.00	Oct-2016	Oct-2036	Simcoe Solar, LLC	20.00	Mar-2017	Mar-2037
Hyline Solar Center, LLC	9.00	Nov-2016	Nov-2036	Thunderegg Solar Center, LLC	10.00	Nov-2016	Nov-2036
ID Solar 1	40.00	Aug-2016	Jan-2036	Vale Air Solar Center, LLC	10.00	Nov-2016	Nov-2036
Morgan Solar	3.00	Oct-2019	Estimated	Vale 1 Solar	3.00	Oct-2019	Estimated
Mt. Home Solar 1, LLC	20.00	Mar-2017	Mar-2037				
Total Solar Nameplate Rating 316.25 MW							

Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Mainline Windfarm	23.00	Dec-2012	Dec-2032
Benson Creek Windfarm	10.00	Mar-2017	Mar-2037	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031	Oregon Trail Wind Park	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm LLC	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Prospector Windfarm	10.00	Mar-2017	Mar-2037
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Durbin Creek Windfarm	10.00	Mar-2017	Mar-2037	Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Golden Valley Wind Park	12.00	Feb-2011	Feb-2031	Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032	Thousand Springs Wind Park	12.00	Jan-2011	Jan-2031
High Mesa Wind Project	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	May-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Jett Creek Windfarm	10.00	Mar-2017	Mar-2037	Willow Spring Windfarm	10.00	Mar-2017	Mar-2037
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW							
Total Nameplate Rating 1,148.62 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements

Project	MW	Contract On-Line Date	End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total Wind Nameplate Rating	**101**		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	November 2012	November 2037
Total Geothermal Nameplate Rating	**35**		
Solar projects			
Jackpot Solar Facility	120	December 2022	Estimated
Total Solar Nameplate Rating	**120**		
Total Nameplate Rating	**256**		

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Flow Modeling

Models

Idaho Power uses two primary models to develop future flow scenarios for the IRP. The Snake River Planning Model (SRPM) is used to model surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to model aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

Model Inputs

The inputs for the 2019 IRP were derived, in part, from management practices outlined in an agreement between the Surface Water Coalition (SWC) and Idaho Groundwater Appropriators (IGWA). The agreement set out specific targets for several management practices that include aquifer recharge, system conversions, and a total reduction in ground water diversions of 240,000 acre-feet. Model inputs also included a long-term analysis of trends in reach gains to the Snake River from Palisades Dam to King Hill. Weather modification activities conducted by Idaho Power and other participating entities were included in the modeling effort.

Recharge capacity modeled for the 2019 IRP included diversions with the capability of diverting all available water at the Snake River below Milner Dam during the winter months under typical release conditions. These diversions can have a significant impact to flows downstream of Milner Dam. Modeled recharge diversions peak at approximately 339,000 acre-ft in IRP year 2025. In IRP year 2025, approximately 145,000 acre-ft of recharge diversions occur above American Falls Reservoir and 195,000 acre-ft is diverted at Milner Dam. Modeled recharge diversions decline only slightly from the peak in 2025 through the end of the modeling period in 2038. The 2019 IRP included approximately 85,000 acre-ft of additional annual recharge not included in the 2017 IRP. This increase in projected recharge activity is based upon recharge activity observed from spring 2016 through spring 2018. The additional annual recharge volume can be attributed to the development of private aquifer recharge and state sponsored recharge demonstrating a higher level of recharge capacity than anticipated in the 2017 IRP.

System conversion projects involve the conversion of ground water supplied irrigated land to surface water-supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources and local ground water districts. The current model assumes a total of 48,000 acres of converted land on the ESPA. This is an increase of approximately 30,000 acres over the 2017 IRP and is based on data collected from a local groundwater district. Water savings for conversion projects are calculated at a rate of 2.0 acre-ft per converted acre. Diversions for conversion projects peak at approximately 95,000 acre-ft in model year 2024 and are held essentially constant through the end of the modeling period in year 2038.

The model accounted for a 190,000 acre-ft decrease in ground water pumping from the ESPA. The decrease was spread evenly over ground water irrigated lands that are subject to the agreement between the SWC and the IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft per year but the agreement allows for a portion of that to be offset by aquifer recharge activities. Based on recent management activity, approximately 50,000 acre-ft per year reduction is accomplished through other forms of mitigation such as private aquifer recharge.

The 2019 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Lower Salmon Falls Dam to Bliss demonstrated a statistically significant decline for the period of 1988 to 2017. The long-term declines are still present, but they have improved since the 2017 IRP. Reach gains to the Snake River increased in 2016 and 2017. The increases in reach gains may be due to a combination of factors including recent high runoff events, good supply of irrigation water, and aquifer recharge activities. The declines calculated for the 2019 IRP are approximately 25 to 30 percent less than those used in the 2017 IRP. This results in additional water in the Snake River throughout the planning period.

Weather modification was added to the model at various levels of development. For IRP years 2019 through 2024, weather modification was increased to reflect projected levels of program development in Eastern Idaho, the Wood River and Boise basins. Beyond IRP year 2024, weather-modification levels in these three basins were held constant through the remainder of the IRP planning period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP planning period.

The modeling also accounts for changes in reach gains from observed water management activities on the ESPA since 2014. Reach gain calculations include management activities that have occurred since 2014. Data from IDWR and other sources were used to determine the magnitude of the management activities and the ESPAM was used to model the projected reach gains. The impact of those management activities can have impacts on reach gains for up to 30 years.

Model Results

The combined model allows for the inclusion of all future management activities, and the resulting reach gains from those management activities into Idaho Power's 2019 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex (HCC), but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and a decrease in ground water pumping, directly impact the annual volume of water expected through the HCC as well as the timing and location of gains within the system.

Overall inflow to Brownlee Reservoir increases from IRP modeled year 2019 through 2024. Flows peak in 2025 with the 50 percent exceedance annual inflow to Brownlee Reservoir at just over 12.33 million acre-ft/year. In 2038, those flows declined to approximately 12.03 million acre-ft per year. For the April through July volume the peak occurs in modeled year 2024 with a volume of 5.58 million acre-ft. In the final modeled year of 2038, the April through July inflow to Brownlee decreases to 5.47 million acre-ft.

The Brownlee inflow volumes for the 2019 IRP are higher than those reported in the 2017 IRP. There are several factors leading to the increase in modeled flows. The change in reach declines had a significant impact on inflows to Brownlee Reservoir. For example, in model year 2036, the increase in Brownlee inflow volume attributable to changes in reach declines between the 2019 and 2017 IRPs is approximately 337,000 acre-feet, Weather modification volume increased by approximately 200,000 acre-ft per year in the 2019 IRP as compared to the 2017 IRP. The other notable change is the observed recharge conducted in 2016 and 2017 exceeded recharge volume assumptions made during the 2017 IRP.

Over 1,000,000 acre-ft water were recharged to the ESPA during 2016 and 2017. While outside the modeling period of 2019 to 2038, the reach gains resulting from this recharge are modeled and significantly increase reach gains for the modeling period. The modeled reach gains from this recharge increased reach gains in the Snake River and inflows to Brownlee Reservoir particularly during the first five years of the modeling period.

2019 Model Parameters (acre-feet/year)

	Managed Recharge						Reach Declines	
Year	Above American Falls	Below American Falls	Total	Weather Modification	System Conversions	Ground Water Pumping Declines	American Falls Inflows	Below Milner Inflows
2019	145,210	192,991	338,201	978,140	96,138	190,053	167,239	135,702
2020	144,682	193,002	337,685	1,164,927	95,105	190,053	182,442	148,039
2021	144,559	193,002	337,562	1,232,907	95,105	190,053	197,646	160,375
2022	144,436	193,052	337,489	1,241,693	96,140	190,053	212,849	172,712
2023	144,680	193,298	337,978	1,252,091	95,105	190,053	228,053	185,049
2024	144,381	193,187	337,568	1,268,605	95,537	190,053	243,256	197,385
2025	144,319	194,802	339,121	1,268,605	94,928	190,053	258,460	209,722
2026	144,319	193,195	337,514	1,268,605	94,928	190,053	273,663	222,058
2027	144,319	193,139	337,459	1,268,605	94,928	190,053	288,867	234,395
2028	144,319	193,024	337,344	1,268,605	94,928	190,053	304,071	246,732
2029	144,319	192,913	337,233	1,268,605	94,928	190,053	319,274	259,068
2030	144,490	192,669	337,159	1,268,605	95,414	190,053	334,478	271,405
2031	143,631	192,550	336,181	1,268,605	95,351	190,053	349,681	283,741
2032	143,508	192,429	335,937	1,268,605	95,351	190,053	364,885	296,078
2033	143,693	192,364	336,056	1,268,605	95,412	190,053	380,088	308,414
2034	143,262	192,001	335,263	1,268,605	95,535	190,053	395,292	320,751
2035	143,865	192,058	335,924	1,268,605	95,535	190,053	410,495	333,088
2036	143,324	191,878	335,202	1,268,605	95,535	190,053	425,699	345,424
2037	143,139	191,691	334,831	1,268,605	95,291	190,053	440,902	357,761
2038	142,467	191,634	334,101	1,268,605	95,172	190,053	456,106	370,097

Hydro Modeling Results (aMW)

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2019	Jan	750	350	1,100	596	204	800	434	177	612
	Feb	787	355	1,141	682	310	993	682	310	993
	Mar	815	276	1,092	588	225	813	588	225	813
	Apr	1,058	406	1,465	750	274	1,024	750	274	1,024
	May	913	432	1,344	875	320	1,195	875	320	1,195
	June	992	385	1,377	678	333	1,011	678	333	1,011
	July	551	292	842	520	282	802	520	282	802
	Aug	466	251	716	437	242	679	437	242	679
	Sept	568	241	809	464	231	696	464	231	696
	Oct	417	215	632	395	206	601	395	206	601
	Nov	343	195	538	347	180	527	347	180	527
	Dec	579	362	941	484	189	673	484	189	673
Annual aMW		**686**	**313**	**1,000**	**568**	**250**	**818**	**555**	**248**	**802**
2020	Jan	758	355	1,113	612	257	869	444	181	625
	Feb	803	365	1,168	689	321	1,010	689	321	1,010
	Mar	820	282	1,103	595	234	828	595	234	828
	Apr	1,072	426	1,498	761	290	1,051	761	290	1,051
	May	931	454	1,385	877	332	1,209	877	332	1,209
	June	1,010	431	1,441	704	335	1,039	704	335	1,039
	July	551	292	843	520	283	803	520	283	803
	Aug	467	251	717	437	243	680	437	243	680
	Sept	581	241	822	468	234	702	468	234	702
	Oct	414	216	629	391	206	597	391	206	597
	Nov	338	197	536	348	181	528	348	181	528
	Dec	584	374	958	486	190	675	486	190	675
Annual aMW		**694**	**324**	**1,018**	**574**	**259**	**833**	**560**	**252**	**812**

*HCC=Hells Canyon Complex, **ROR=Run of River

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2021	Jan	760	355	1,115	613	257	870	446	182	628
	Feb	803	365	1,168	690	320	1,010	690	320	1,010
	Mar	824	283	1,107	602	235	837	602	235	837
	Apr	1,084	428	1,512	769	292	1,061	769	292	1,061
	May	946	455	1,401	882	334	1,216	882	334	1,216
	June	1,024	432	1,456	708	336	1,044	708	336	1,044
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	682	438	244	682
	Sept	584	241	826	470	234	704	470	234	704
	Oct	415	216	631	390	207	597	390	207	597
	Nov	337	198	535	348	181	529	348	181	529
	Dec	585	376	961	487	190	677	487	190	677
Annual aMW		**698**	**324**	**1,023**	**576**	**259**	**836**	**562**	**253**	**816**
2022	Jan	760	355	1,115	613	260	873	446	182	628
	Feb	803	366	1,168	690	320	1,010	690	320	1,010
	Mar	824	284	1,107	602	235	837	602	235	837
	Apr	1,085	428	1,513	770	295	1,065	770	295	1,065
	May	946	458	1,404	882	336	1,217	882	336	1,217
	June	1,025	435	1,461	710	336	1,046	710	336	1,046
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	681	438	244	681
	Sept	585	241	826	470	234	704	470	234	704
	Oct	415	216	630	390	207	597	390	207	597
	Nov	337	198	535	347	181	528	347	181	528
	Dec	586	378	964	487	190	677	487	190	677
Annual aMW		**698**	**325**	**1,024**	**576**	**260**	**837**	**563**	**254**	**816**

Year	Month	50th Percentile			70th Percentile			90th Percentile		
		HCC*	ROR**	Total	HCC	ROR	Total	HCC	ROR	Total
2023	Jan	759	356	1,115	613	265	877	445	182	628
	Feb	802	366	1,168	689	320	1,009	689	320	1,009
	Mar	824	285	1,109	601	236	837	601	236	837
	Apr	1,084	428	1,513	769	298	1,068	769	298	1,068
	May	945	461	1,406	882	339	1,221	882	339	1,221
	June	1,032	441	1,472	711	338	1,049	711	338	1,049
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	437	244	681	437	244	681
	Sept	586	241	827	469	234	703	469	234	703
	Oct	415	216	631	390	207	597	390	207	597
	Nov	335	198	533	347	181	529	347	181	529
	Dec	586	380	966	487	190	678	487	190	678
Annual aMW		**699**	**326**	**1,025**	**576**	**261**	**838**	**562**	**254**	**817**
2024	Jan	759	357	1,116	613	271	884	445	182	627
	Feb	802	366	1,168	688	320	1,007	688	320	1,007
	Mar	824	286	1,110	601	236	837	601	236	837
	Apr	1,085	429	1,513	770	300	1,070	770	300	1,070
	May	947	463	1,409	882	341	1,223	882	341	1,223
	June	1,033	444	1,477	712	338	1,050	712	338	1,050
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	717	437	244	681	437	244	681
	Sept	586	241	828	468	234	703	468	234	703
	Oct	415	215	630	390	207	596	390	207	596
	Nov	335	198	533	348	181	529	348	181	529
	Dec	586	381	968	487	190	678	487	190	678
Annual aMW		**699**	**327**	**1,026**	**576**	**262**	**838**	**562**	**255**	**817**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2025	Jan	759	356	1,115	612	268	880	444	182	627
	Feb	800	366	1,165	688	319	1,007	688	319	1,007
	Mar	823	286	1,109	600	235	835	600	235	835
	Apr	1,084	428	1,512	768	300	1,068	768	300	1,068
	May	946	462	1,409	882	341	1,223	882	341	1,223
	June	1,032	443	1,475	711	337	1,049	711	337	1,049
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	716	436	244	680	436	244	680
	Sept	584	241	825	467	234	701	467	234	701
	Oct	414	215	630	389	206	596	389	206	596
	Nov	336	198	534	348	181	529	348	181	529
	Dec	586	380	966	486	190	677	486	190	677
Annual aMW		**698**	**327**	**1,025**	**576**	**262**	**837**	**562**	**255**	**816**
2026	Jan	758	355	1,113	611	265	877	444	182	626
	Feb	797	365	1,162	687	319	1,006	687	319	1,006
	Mar	822	286	1,108	599	234	833	599	234	833
	Apr	1,083	428	1,511	769	300	1,068	769	300	1,068
	May	946	462	1,408	882	341	1,222	882	341	1,222
	June	1,032	443	1,474	711	337	1,048	711	337	1,048
	July	549	292	841	519	284	802	519	284	802
	Aug	465	251	716	436	244	680	436	244	680
	Sept	582	241	823	466	234	700	466	234	700
	Oct	413	215	628	389	206	596	389	206	596
	Nov	337	198	534	348	181	529	348	181	529
	Dec	584	378	962	485	190	675	485	190	675
Annual aMW		**697**	**326**	**1,023**	**575**	**261**	**836**	**561**	**254**	**815**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2027	Jan	757	354	1,111	611	262	872	443	181	625
	Feb	792	364	1,156	685	318	1,003	685	318	1,003
	Mar	821	284	1,106	599	234	832	599	234	832
	Apr	1,082	427	1,509	767	299	1,066	767	299	1,066
	May	946	461	1,407	882	340	1,222	882	340	1,222
	June	1,031	441	1,472	710	337	1,047	710	337	1,047
	July	549	292	840	518	283	801	518	283	801
	Aug	465	251	715	435	243	679	435	243	679
	Sept	579	241	820	464	234	698	464	234	698
	Oct	412	215	627	390	206	596	390	206	596
	Nov	337	198	535	347	181	528	347	181	528
	Dec	583	376	959	485	190	675	485	190	675
Annual aMW		**696**	**325**	**1,021**	**574**	**261**	**835**	**560**	**254**	**814**
2028	Jan	756	353	1,109	610	258	868	443	181	623
	Feb	789	362	1,151	684	316	1,000	684	316	1,000
	Mar	820	283	1,102	598	232	830	598	232	830
	Apr	1,082	427	1,509	767	298	1,065	767	298	1,065
	May	945	460	1,404	882	339	1,221	882	339	1,221
	June	1,030	440	1,470	709	337	1,046	709	337	1,046
	July	548	291	840	517	283	800	517	283	800
	Aug	464	250	714	435	243	678	435	243	678
	Sept	576	241	817	463	234	697	463	234	697
	Oct	411	215	626	389	206	595	389	206	595
	Nov	338	198	536	347	181	528	347	181	528
	Dec	581	373	953	483	189	673	483	189	673
Annual aMW		**695**	**324**	**1,019**	**574**	**260**	**833**	**560**	**253**	**813**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2029	Jan	755	352	1,107	609	253	861	441	180	621
	Feb	786	360	1,146	683	314	997	683	314	997
	Mar	819	281	1,100	596	230	826	596	230	826
	Apr	1,081	426	1,507	767	298	1,065	767	298	1,065
	May	944	456	1,400	881	338	1,219	881	338	1,219
	June	1,029	439	1,468	708	336	1,044	708	336	1,044
	July	548	291	839	517	283	800	517	283	800
	Aug	463	250	713	434	243	677	434	243	677
	Sept	573	240	813	461	233	694	461	233	694
	Oct	410	215	625	389	206	595	389	206	595
	Nov	339	197	537	347	181	528	347	181	528
	Dec	579	370	949	482	189	671	482	189	671
Annual aMW		**694**	**323**	**1,017**	**573**	**259**	**831**	**559**	**253**	**812**
2030	Jan	753	351	1,104	606	247	853	441	178	619
	Feb	783	359	1,141	682	312	994	682	312	994
	Mar	817	280	1,097	596	227	823	596	227	823
	Apr	1,079	426	1,505	766	297	1,063	766	297	1,063
	May	944	455	1,399	881	331	1,212	881	331	1,212
	June	1,026	436	1,462	707	335	1,041	707	335	1,041
	July	547	291	838	516	283	799	516	283	799
	Aug	463	250	712	434	243	676	434	243	676
	Sept	569	240	809	459	233	692	459	233	692
	Oct	410	215	625	390	206	595	390	206	595
	Nov	341	197	538	347	181	527	347	181	527
	Dec	577	366	943	481	189	670	481	189	670
Annual aMW		**692**	**322**	**1,014**	**572**	**257**	**829**	**558**	**251**	**809**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2031	Jan	752	349	1,101	601	241	842	440	177	617
	Feb	781	359	1,140	680	308	988	680	308	988
	Mar	816	279	1,095	595	225	819	595	225	819
	Apr	1,078	425	1,503	765	297	1,062	765	297	1,062
	May	944	454	1,398	881	332	1,212	881	332	1,212
	June	1,022	434	1,455	706	335	1,040	706	335	1,040
	July	546	291	837	515	283	798	515	283	798
	Aug	462	250	712	433	242	675	433	242	675
	Sept	566	240	806	453	232	686	453	232	686
	Oct	411	214	626	390	205	596	390	205	596
	Nov	340	197	536	346	180	527	346	180	527
	Dec	575	363	937	480	189	668	480	189	668
Annual aMW		**691**	**321**	**1,012**	**570**	**256**	**826**	**557**	**250**	**807**
2032	Jan	750	348	1,098	600	236	835	440	177	617
	Feb	779	358	1,136	679	306	985	679	306	985
	Mar	815	278	1,093	593	224	817	593	224	817
	Apr	1,077	424	1,501	765	295	1,060	765	295	1,060
	May	943	453	1,396	880	332	1,212	880	332	1,212
	June	1,017	432	1,448	705	335	1,040	705	335	1,040
	July	546	291	836	515	282	797	515	282	797
	Aug	462	249	711	432	242	674	432	242	674
	Sept	562	240	802	452	232	684	452	232	684
	Oct	413	214	627	390	205	595	390	205	595
	Nov	340	196	536	346	180	526	346	180	526
	Dec	573	359	931	478	189	667	478	189	667
Annual aMW		**690**	**320**	**1,010**	**569**	**255**	**824**	**556**	**250**	**806**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2033	Jan	749	347	1,096	599	230	829	438	177	615
	Feb	777	357	1,133	677	305	982	677	305	982
	Mar	814	277	1,090	592	223	815	592	223	815
	Apr	1,076	424	1,499	763	293	1,056	763	293	1,056
	May	942	452	1,395	880	330	1,210	880	330	1,210
	June	1,012	430	1,443	704	334	1,038	704	334	1,038
	July	545	291	836	514	282	796	514	282	796
	Aug	461	249	710	432	242	674	432	242	674
	Sept	558	240	798	450	232	682	450	232	682
	Oct	414	214	628	390	205	595	390	205	595
	Nov	341	196	537	346	180	526	346	180	526
	Dec	572	355	927	475	188	664	475	188	664
Annual aMW		**688**	**319**	**1,008**	**568**	**254**	**822**	**555**	**249**	**804**
2034	Jan	748	346	1,093	598	225	823	437	177	613
	Feb	775	356	1,131	676	304	980	676	304	980
	Mar	813	274	1,087	590	222	812	590	222	812
	Apr	1,074	423	1,497	763	291	1,053	763	291	1,053
	May	941	451	1,393	879	329	1,209	879	329	1,209
	June	1,011	429	1,440	702	334	1,036	702	334	1,036
	July	544	290	835	514	282	795	514	282	795
	Aug	460	249	709	431	242	673	431	242	673
	Sept	554	239	794	448	231	679	448	231	679
	Oct	416	214	630	391	205	596	391	205	596
	Nov	341	196	537	345	180	525	345	180	525
	Dec	571	350	921	473	188	661	473	188	661
Annual aMW		**687**	**318**	**1,005**	**567**	**253**	**820**	**554**	**249**	**803**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2035	Jan	746	344	1,091	598	219	817	436	176	612
	Feb	768	354	1,121	674	303	977	674	303	977
	Mar	811	273	1,084	589	221	809	589	221	809
	Apr	1,072	422	1,494	762	289	1,051	762	289	1,051
	May	941	450	1,391	879	329	1,208	879	329	1,208
	June	1,011	429	1,439	701	333	1,034	701	333	1,034
	July	544	290	834	513	282	794	513	282	794
	Aug	460	249	708	430	241	672	430	241	672
	Sept	550	239	789	446	231	677	446	231	677
	Oct	419	213	632	390	205	595	390	205	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	571	346	917	471	188	659	471	188	659
Annual aMW		**686**	**317**	**1,003**	**566**	**252**	**818**	**553**	**248**	**801**
2036	Jan	745	344	1,089	594	217	811	434	176	610
	Feb	765	351	1,117	673	301	975	673	301	975
	Mar	810	272	1,082	588	220	807	588	220	807
	Apr	1,072	421	1,493	761	288	1,048	761	288	1,048
	May	940	450	1,390	879	326	1,205	879	326	1,205
	June	1,009	427	1,437	699	333	1,032	699	333	1,032
	July	543	290	833	512	281	794	512	281	794
	Aug	459	248	707	430	241	671	430	241	671
	Sept	546	239	785	444	230	675	444	230	675
	Oct	420	213	633	390	204	595	390	204	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	570	341	911	471	188	658	471	188	658
Annual aMW		**685**	**316**	**1,001**	**565**	**251**	**816**	**552**	**247**	**800**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2037	Jan	743	343	1,086	592	215	806	433	175	608
	Feb	765	350	1,115	672	299	971	672	299	971
	Mar	809	270	1,079	585	217	802	585	217	802
	Apr	1,069	420	1,489	760	287	1,047	760	287	1,047
	May	940	449	1,388	879	326	1,204	879	326	1,204
	June	1,008	424	1,432	698	333	1,030	698	333	1,030
	July	542	290	832	511	281	793	511	281	793
	Aug	458	248	707	429	241	670	429	241	670
	Sept	544	239	783	442	230	672	442	230	672
	Oct	419	213	632	391	204	595	391	204	595
	Nov	340	194	534	346	179	525	346	179	525
	Dec	568	336	905	469	187	656	469	187	656
Annual aMW		**684**	**315**	**999**	**564**	**250**	**814**	**551**	**247**	**798**
2038	Jan	738	342	1,079	591	203	794	432	175	607
	Feb	762	351	1,113	670	295	964	670	295	964
	Mar	808	269	1,077	584	211	795	584	211	795
	Apr	1,067	419	1,487	759	286	1,045	759	286	1,045
	May	940	447	1,387	879	325	1,203	879	325	1,203
	June	1,023	423	1,445	696	332	1,029	696	332	1,029
	July	542	289	831	511	281	792	511	281	792
	Aug	458	248	706	428	241	669	428	241	669
	Sept	543	239	782	440	229	669	440	229	669
	Oct	418	213	631	391	204	594	391	204	594
	Nov	339	195	534	346	179	525	346	179	525
	Dec	568	331	899	468	187	655	468	187	655
Annual aMW		**684**	**314**	**997**	**564**	**248**	**811**	**550**	**245**	**796**

LONG-TERM CAPACITY EXPANSION RESULTS (MW)

	Portfolio 1					Portfolio 13				
Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Price Forecast				
Carbon Assumption:	Zero Carbon Price Forecast					Zero Carbon Price Forecast				
B2H Assumption:	No B2H					B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022					(177)					(177)
2023		120		5			120			
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028			10	5						
2029		80	40	5						
2030		40	20	5					5	
2031		80	20	5					5	
2032	111			5					5	
2033									5	
2034	300				(531)				5	(531)
2035	411					411	80	50	5	
2036									5	
2037	56					300			5	
2038	56								5	
Nameplate Total (MW)	933	320	90	50	(1,026)	711	200	50	45	(1,026)
B2H	–					500				
Net Build	367					480				

	Portfolio 2					Portfolio 14				
Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast				
Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast				
B2H Assumption:	No B2H					B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022					(177)					(177)
2023		120		5			120			
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028		40	30	5						
2029		40	20	5						
2030	300			5					5	
2031				5					5	
2032				5					5	
2033	111								5	
2034					(531)				5	(531)
2035	411	120	30			300	160	70	5	
2036						300	40	10	5	
2037	56								5	
2038	56								5	
Nameplate Total (MW)	933	320	80	50	(1,026)	600	320	80	45	(1,026)
B2H	–					500				
Net Build	357					519				

	Portfolio 3						Portfolio 15					
Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast						Generational Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			480						400			
2022			120			(177)		100				(177)
2023					5							
2024		100			5							
2025		100	320		5	(133)						(133)
2026		100			5	(180)						(180)
2027			200	80	5			100				
2028					5			100			5	(174)
2029		100	40		5	(174)		100			5	
2030	300	100			5			100	440		5	(177)
2031			5		5				200	80	5	
2032					5						5	
2033	111						300				5	
2034						(177)					5	
2035	300										5	
2036											5	
2037											5	
2038	111						300					
Nameplate Total (MW)	822	500	1,165	80	50	(1,026)	600	500	1,040	80	50	(1,026)
B2H	-						500					
Net Build	1,591						1,744					

	Portfolio 4						Portfolio 16					
Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast					
Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			480									
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025		100	320		5	(133)						(133)
2026		100	40	30	5	(180)						(180)
2027		100	200	50	5			100	920	50	5	-
2028		100			5	(174)		100			5	(174)
2029	300	100			5			100				
2030		100			5		111	100			5	(177)
2031					5			100	120	30	5	
2032					5			100			5	
2033	111						300				5	
2034						(177)					5	
2035	300										5	
2036											5	
2037											5	
2038	111											
Nameplate Total (MW)	822	600	1,160	80	50	(1,026)	411	600	1,160	80	50	(1,026)
B2H							500					
Net Build	1,686						1,775					

	Portfolio 5							Portfolio 17				
Gas Assumption:	Mid Gas Price Forecast							Mid Gas Price Forecast				
Carbon Assumption:	Zero Carbon Price Forecast							Zero Carbon Price Forecast				
B2H Assumption:	No B2H							B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Geothermal**	**Nuclear**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019							(127)					(127)
2020							(58)					(58)
2021												
2022		120										
2023						5						
2024						5						
2025						5	(133)					(133)
2026			5			5						
2027						5						
2028						5						
2029						5						
2030		5				5						
2031						5						
2032		40	30			5					5	
2033		40	20		60						5	
2034							(708)				5	(708)
2035	633	290	30					411	240	80	5	
2036					60						5	
2037					60			111			5	
2038		120		30							5	
Nameplate Total (MW)	633	615	85	30	180	50	(1,026)	522	240	80	35	(1,026)
B2H	–							500				
Net Build	567							351				

	Portfolio 6					Portfolio 18						
Gas Assumption:	Mid Gas Price Forecast					Mid Gas Price Forecast						
Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Geothermal**	**Biomass**	**Demand Response**	**Coal Exit**
2019					(127)							(127)
2020					(58)							(58)
2021												
2022		120										
2023				5								
2024				5								
2025				5	(133)							(133)
2026				5								
2027				5								
2028				5								
2029				5								
2030				5								
2031				5								
2032		40	30	5							5	
2033		80	30		(177)		40	30			5	
2034	300				(531)		45	10			5	(708)
2035	411	485	20			300	205	40			5	
2036							160	10			5	
2037	111					56			30	30	5	
2038		80									5	
Nameplate Total (MW)	822	805	80	50	(1,026)	356	450	90	30	30	35	(1,026)
B2H	–					500						
Net Build	731					465						

	Portfolio 7						Portfolio 19					
Gas Assumption:	Mid Gas Price Forecast						Mid Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast						Generational Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021		100	440					100	400			
2022		100	440			(177)		100				(177)
2023		100	160	20	5			100				
2024		100			5							
2025		100			5	(133)						(133)
2026		100			5	(180)						(180)
2027					5			100	560	40	5	
2028			120	60	5	(174)		100			5	(174)
2029	300				5			100	80	40	5	
2030					5	(177)			5		5	(177)
2031	300				5				5		5	
2032					5						5	
2033	111						300					
2034												
2035			5									
2036	111											
2037												
2038							111					
Nameplate Total (MW)	822	600	1,165	80	50	(1,026)	411	600	1,050	80	30	(1,026)
B2H	–						500					
Net Build	1,691						1,645					

	Portfolio 8						**Portfolio 20**				
Gas Assumption:	Mid Gas Price Forecast						Mid Gas Price Forecast				
Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
B2H Assumption:	No B2H						B2H in Service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Coal Exit**
2019						(127)					(127)
2020						(58)					(58)
2021			520								
2022		100	120			(177)					(177)
2023		100			5				120		
2024		100	320		5						
2025		100			5	(133)					
2026		100			5	(180)					(180)
2027		100			5			100	965	30	
2028	300		200	80	5	(174)		100			(174)
2029			5		5			100	80	50	
2030					5			100			(177)
2031			5		5		222	100			
2032					5			100			
2033									5		
2034	111					(177)					(133)
2035	300						300				
2036											
2037	111										
2038											
Nameplate Total (MW)	822	600	1,170	80	50	(1,026)	522	600	1,170	80	1,026
B2H	–						500				
Net Build	1,696						1,846				

	Portfolio 9						Portfolio 21					
Gas Assumption:	High Gas Price Forecast						High Gas Price Forecast					
Carbon Assumption:	Zero Carbon Price Forecast						Zero Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021			520									
2022												
2023			120		5							
2024												
2025					5	(133)						(133)
2026					5							
2027			40	30	5							
2028					5							
2029			80	30	5							
2030			320									
2031					5							
2032					5				520			
2033		100			5			100	240			
2034	300	100			5	(708)		100	40	30	5	(708)
2035	411	100	85	20			300	100	245	50	5	
2036		100						100			5	
2037		100						100			5	
2038	56						111	100			5	
Nameplate Total (MW)	767	500	1,165	80	50	(1,026)	411	600	1,045	80	25	(1,026)
B2H	–						500					
Net Build	1,536						1,635					

	Portfolio 10						Portfolio 22						
Gas Assumption:	High Gas Price Forecast						High Gas Price Forecast						
Carbon Assumption:	Planning Carbon Price Forecast						Planning Carbon Price Forecast						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Nuclear**	**Demand Response**	**Coal Exit**
2019						(127)							(127)
2020						(58)							(58)
2021			480										
2022			120										
2023					5								
2024													
2025			40	30		(133)							(133)
2026			40	20									
2027			360										
2028		100	120	30									
2029		100											
2030		100	5		5								
2031		100			5								
2032		100			5			100	480				
2033		100			5			100	240				
2034					5	(708)		100	80	20			(708)
2035	600		5		5		300	100	245	60		5	
2036	300							100				5	
2037								100				5	
2038											60	5	
Nameplate Total (MW)	900	600	1,170	80	35	(1,026)	300	600	1,045	80	60	20	(1,026)
B2H	–						500						
Net Build	1,759						1,579						

	Portfolio 11								Portfolio 23					
Gas Assumption:	High Gas Price Forecast								High Gas Price Forecast					
Carbon Assumption:	Generational Carbon Price Forecast								Generational Carbon Price Forecast					
B2H Assumption:	No B2H								B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Nuclear**	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019								(127)						(127)
2020								(58)						(58)
2021			480							100	360			
2022		100	360					(177)		100				(177)
2023		100				30	5			100				
2024		100					5			100				
2025								(133)						(133)
2026		200	325	80		30	5							
2027		200				30	5			200	320			
2028		100				30	5	(174)		200	125			(174)
2029		100				30	5			100	40	10		
2030						30	5			100				(177)
2031			5			30	5				160	70		
2032							5							
2033							5	(180)	300					
2034	300							(177)			40			(180)
2035					60					100				
2036					60								5	
2037					60					100	5		5	
2038	111								300				5	
Nameplate Total (MW)	411	900	1,170	80	180	210	50	(1,026)	600	1,200	1,050	80	15	(1,026)
B2H	–								500					
Net Build	1,975								2,419					

	Portfolio 12							Portfolio 24					
Gas Assumption:	High Gas Price Forecast							High Gas Price Forecast					
Carbon Assumption:	High Carbon Price Forecast							High Carbon Price Forecast					
B2H Assumption:	No B2H							B2H in Service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**Wind**	**Solar**	**Battery**	**Pumped Storage**	**Biomass**	**Coal Exit**
2019							(127)						(127)
2020							(58)						(58)
2021			480						320				
2022		100	400				(177)	100					
2023		100	80										(177)
2024		100		5									
2025	56	200	165	75		5	(133)						(133)
2026		200	40	10		5	(180)						(180)
2027	111	200		5		5			160	70			
2028		100		5	30	5	(174)		40	10			(174)
2029	56	100			30								
2030						5	(177)						(177)
2031	300	100	5			5					500		
2032						5		100	325				
2033						5		200	200				
2034						5		200				30	
2035	170							200					
2036						5		200					
2037								200					
2038													
Nameplate Total (MW)	692	1,200	1,170	100	60	50	(1,026)	1,200	1,045	80	500	30	(1,026)
B2H	–							500					
Net Build	2,246							2,329					

Manual Optimization Results (MW)

PGPC (1)	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030	**PGPC B2H (1)**	Bridger Exits 2022, 2026, 2028, 2030
	Gas Assumption:	Planning Gas Price Forecast		Planning Gas Price Forecast
	Carbon Assumption:	Planning Carbon Price Forecast		Planning Carbon Price Forecast
	B2H Assumption:	No B2H		B2H in service 2026

	Gas	Solar	Battery	Demand Response	Coal Exit	Gas	Solar	Battery	Demand Response	Coal Exit
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5	(180)					(180)
2027	111	40	30	5						
2028		40	20	5	(174)					(174)
2029	300			5						
2030				5	(177)		40	30	5	(177)
2031	300			5		300			5	
2032				5					5	
2033		40	10						5	
2034		80	20				40	20	5	
2035	56						80	20	5	
2036	56						120	10	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	320	80	50	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	357					410				

PGPC (2)	Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034				**PGPC B2H (2)**	Bridger Exits 2022, 2028, 2034, 2034			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5						
2027				5						
2028		40	30	5	(180)					(180)
2029	300			5						
2030				5					5	
2031		40	20	5					5	
2032		40	10	5					5	
2033		80	20						5	
2034	56				(351)		40	30	5	(351)
2035	411					300	160	30	5	
2036	56						80	20	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	320	80	50	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	375					410				

PGPC (3)	Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034				**PGPC B2H (3)**	Bridger Exits 2022, 2026, 2034, 2034			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5						
2024				5						
2025				5	(133)					(133)
2026				5	(180)					(180)
2027	300			5						
2028		40	30	5						
2029				5						
2030				5					5	
2031		40	20	5					5	
2032		40	10	5					5	
2033		80	20						5	
2034	56				(351)		40	30	5	(351)
2035	411					300	160	30	5	
2036	56						80	20	5	
2037	111					56			5	
2038						56			5	
Nameplate Total (MW)	933	520	80	30	(1,026)	411	400	80	45	(1,026)
B2H	–					500				
Net Build	537					410				

PGPC (4)	Scenario 4 Assumption:	Bridger Exits Vary				**PGPC B2H (4)**	Bridger Exits Vary			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	Planning Carbon Price Forecast					Planning Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)					(177)
2023				5			120			
2024				5						
2025				5	(133)					(133)
2026				5						(180)
2027				5						
2028		40		5	(180)					(174)
2029	167	80	50	5						
2030		40	10	5					5	(177)
2031	56			5		111	120	50	5	
2032		80	20	5			80	10	5	
2033	111					111			5	
2034					(351)				5	
2035	411					56			5	
2036	56						80	20	5	
2037	56					56	40		5	
2038	56					56			5	
Nameplate Total (MW)	911	360	80	50	(1,026)	389	440	80	45	(1,026)
B2H	–					500				
Net Build	375					428				

PGHC (1)	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030					**PGHC B2H (1)**	Bridger Exits 2022, 2026, 2028, 2030				
	Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast				
	Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
	B2H Assumption:	No B2H						B2H in service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5	(180)						(180)
2027			280	50	5						5	
2028			80	20	5	(174)					5	(174)
2029	300				5							
2030					5	(177)					5	(177)
2031	111		600	10	5		56		200	80	5	
2032	56				5				160		5	
2033	300								320		5	
2034								400	360		5	
2035							56				5	
2036							56				5	
2037							56				5	
2038		600	80				56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

	PGHC (2)						PGHC B2H (2)					
Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034						Bridger Exits 2022, 2028, 2034, 2034					
Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast					
Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast					
B2H Assumption:	No B2H						B2H in service 2026					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5							
2027					5						5	
2028			40		5	(180)					5	(180)
2029			440	80	5							
2030	300		480		5						5	
2031					5						5	
2032					5						5	
2033											5	
2034	300	400				(351)			40	30	5	(351)
2035	56		80				111	400	1,000	50	5	
2036	56	200					56				5	
2037	56						56				5	
2038							56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

PGHC (3)	Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034					**PGHC B2H (3)**	Bridger Exits 2022, 2026, 2034, 2034				
	Gas Assumption:	Planning Gas Price Forecast						Planning Gas Price Forecast				
	Carbon Assumption:	High Carbon Price Forecast						High Carbon Price Forecast				
	B2H Assumption:	No B2H						B2H in service 2026				
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)						(127)
2020						(58)						(58)
2021												
2022			120			(177)			120			(177)
2023					5							
2024					5							
2025					5	(133)						(133)
2026					5	(180)						(180)
2027			160	70	5						5	
2028			120	10	5						5	
2029			200		5							
2030			480		5						5	
2031	300				5						5	
2032					5						5	
2033											5	
2034						(351)			40	30	5	(351)
2035	300	400	80				111	400	1,000	50	5	
2036	56						56				5	
2037	56	200					56				5	
2038	56						56					
Nameplate Total (MW)	767	600	1,160	80	50	(1,026)	278	400	1,160	80	50	(1,026)
B2H	–						500					
Net Build	1,631						1,442					

PGHC (4)	Scenario 4 Assumption:	Bridger Exits Vary				**PGHC B2H (4)**	Bridger Exits Vary			
	Gas Assumption:	Planning Gas Price Forecast					Planning Gas Price Forecast			
	Carbon Assumption:	High Carbon Price Forecast					High Carbon Price Forecast			
	B2H Assumption:	No B2H					B2H in service 2026			
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019					(127)					(127)
2020					(58)					(58)
2021										
2022		120			(177)		120			(177)
2023				5					5	
2024				5					5	
2025				5	(133)				5	(133)
2026				5	(180)				5	(180)
2027	56	80	50	5					5	
2028		80	20	5	(174)				5	(174)
2029	167	120	10	5					5	
2030				5	(177)				5	
2031	300	240		5			40	30	5	
2032				5			40	20	5	
2033	111						80	20		
2034							80	10		(177)
2035	56					222	40			
2036	56					56				
2037	56					56	40			
2038		440					280			
Nameplate Total (MW)	800	1,080	80	50	(1,026)	333	720	80	50	(1,026)
B2H	–					500				
Net Build	984					657				

HGHC (1)		
	Scenario 1 Assumption:	Bridger Exits 2022, 2026, 2028, 2030
	Gas Assumption:	High Gas Price Forecast
	Carbon Assumption:	High Carbon Price Forecast
	B2H Assumption:	No B2H

	Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit
2019									(127)
2020									(58)
2021									
2022		120							(177)
2023								5	
2024								5	
2025								5	(133)
2026								5	(180)
2027		200	50					5	
2028		80	30					5	(174)
2029	1,200	760		30			30	5	
2030				30			30	5	(177)
2031						500		5	
2032								5	
2033									
2034									
2035									
2036									
2037					60				
2038					60				
Nameplate Total (MW)	1,200	1,160	80	60	120	500	60	50	(1,026)
B2H	–								
Net Build	2,504								

HGHC B2H (1)
Bridger Exits 2022, 2026, 2028, 2030
High Gas Price Forecast
High Carbon Price Forecast
B2H in service 2026

	Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019								(127)
2020								(58)
2021								
2022		120						(177)
2023							5	
2024							5	
2025							5	(133)
2026							5	(180)
2027							5	
2028							5	(174)
2029							5	
2030							5	(177)
2031		320	80	30		30	5	
2032		200					5	
2033								
2034	100	520						
2035	500			30				
2036	500					30		
2037	100				60			
2038					60			
Nameplate Total (MW)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	500							
Net Build	2,204							

HGHC (2)

Scenario 2 Assumption:	Bridger Exits 2022, 2028, 2034, 2034
Gas Assumption:	High Gas Price Forecast
Carbon Assumption:	High Carbon Price Forecast
B2H Assumption:	No B2H

	Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit
2019									(127)
2020									(58)
2021									
2022		120							(177)
2023								5	
2024								5	
2025								5	(133)
2026								5	
2027								5	
2028		40						5	(180)
2029		400	80					5	
2030		360						5	
2031	200	240		30				5	
2032	300						30	5	
2033	600			30					
2034						500			(351)
2035									
2036							30		
2037					60				
2038					60				
Nameplate Total (MW)	1,100	1,160	80	60	120	500	60	50	(1,026)
B2H	–								
Net Build	2,104								

HGHC B2H (2)

Bridger Exits 2022, 2028, 2034, 2034
High Gas Price Forecast
High Carbon Price Forecast
B2H in service 2026

	Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019								(127)
2020								(58)
2021								
2022		120						(177)
2023							5	
2024							5	
2025							5	(133)
2026							5	
2027							5	
2028							5	(180)
2029							5	
2030							5	
2031							5	
2032							5	
2033								
2034		40						(351)
2035		1,000	80	60		60		
2036	1,100							
2037	100				60			
2038					60			
Nameplate Total (MW)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	500							
Net Build	2,204							

	HGHC (3)									HGHC B2H (3)							
Scenario 3 Assumption:	Bridger Exits 2022, 2026, 2034, 2034									Bridger Exits 2022, 2026, 2034, 2034							
Gas Assumption:	High Gas Price Forecast									High Gas Price Forecast							
Carbon Assumption:	High Carbon Price Forecast									High Carbon Price Forecast							
B2H Assumption:	No B2H									B2H in service 2026							
	Wind	**Solar**	**Battery**	**Geothermal**	**Nuclear**	**Pumped Storage**	**Biomass**	**Demand Response**	**Coal Exit**	**Wind**	**Solar**	**Battery**	**Geothermal**	**Nuclear**	**Biomass**	**Demand Response**	**Coal Exit**
2019									(127)								(127)
2020									(58)								(58)
2021																	
2022		120							(177)		120						(177)
2023								5								5	
2024								5								5	
2025								5	(133)							5	(133)
2026								5	(180)							5	(180)
2027		160	70					5								5	
2028		120	10					5								5	
2029		200						5								5	
2030		320					30	5								5	
2031	200	240		30				5								5	
2032	300						30	5								5	
2033	600			30													
2034						500			(351)		40						(351)
2035											1,000	80	60		60		
2036										1,100							
2037	100				60					100				60			
2038					60									60			
Nameplate Total (MW)	1,200	1,160	80	60	120	500	60	50	(1,026)	1,200	1,160	80	60	120	60	50	(1,026)
B2H	–									500							
Net Build	2,204									2,204							

HGHC (4)
Scenario 4 Assumption: Bridger Exits Vary
Gas Assumption: High Gas Price Forecast
Carbon Assumption: High Carbon Price Forecast
B2H Assumption: No B2H

HGHC B2H (4)
Bridger Exits Vary
High Gas Price Forecast
High Carbon Price Forecast
B2H in service 2026

	HGHC (4) Wind	Solar	Battery	Geothermal	Nuclear	Pumped Storage	Biomass	Demand Response	Coal Exit	HGHC B2H (4) Wind	Solar	Battery	Geothermal	Nuclear	Biomass	Demand Response	Coal Exit
2019									(127)								(127)
2020									(58)								(58)
2021																	
2022		120							(177)		120						(177)
2023								5								5	
2024								5								5	
2025								5	(133)							5	(133)
2026								5	(180)							5	(180)
2027						500		5								5	
2028								5	(174)							5	(174)
2029								5								5	
2030								5	(177)							5	(177)
2031		160	70		60			5			160	70		60		5	
2032	100	80	10					5		100	80	10				5	
2033					60						240						
2034		200												60			
2035		200		30							160		30				
2036					60					200	160				30		
2037	200	200					30			100				60			
2038	800	200								700	240						
Nameplate Total (MW)	1,100	1,160	80	30	180	500	30	50	(1,026)	1,100	1,160	80	30	180	30	50	(1,026)
B2H	–									500							
Net Build	2,104									2,104							

OREGON CARBON EMISSION FORECAST

Idaho Power anticipates the 2019 IRP carbon emission forecast will be used to establish a target for Idaho Power compliance with the proposed Oregon Cap and Trade Legislation. Idaho Power carefully reviewed historical emissions and emissions assumptions in the portfolio modeling and output.

The Total Carbon Dioxide (CO_2) Emissions forecast is composed of results from the AURORA modeling, policy adjustments to IRP forecast assumptions and a Market Volatility adjustment. The modeled AURORA resource dispatch from Idaho Power's preferred resource portfolio, Portfolio 14, is the basis for the emissions forecast. The AURORA emissions forecast consists of the emissions from the modeled operation of Idaho Power's resources and emissions based on forecasted purchased energy. Emissions from forecasted purchased energy is estimated to contribute 0.47 short tons per MWh, which is in-line with the unspecified market purchases used by the California Air Resource Board in their Cap and Trade program.

The hydro forecast in the 2019 IRP AURORA modeling assumes future increases in hydro generation based on expansion of Idaho Power's cloud seeding program and certain State of Idaho groundwater management activities. The actual results from these hydro generation programs may not result in the forecasted increase in generation. Cloud seeding expansion is subject to regulatory review and funding and therefore, was removed from carbon forecast modeling. Groundwater management activities, such as managed aquifer recharge has exceeded the State of Idaho's goals in 2017 and 2018, resulting in reduced wintertime hydro generation production. Idaho Power is concerned that trend may continue and thus feels that carbon forecast modeling should use a more conservative hydrogeneration assumption.

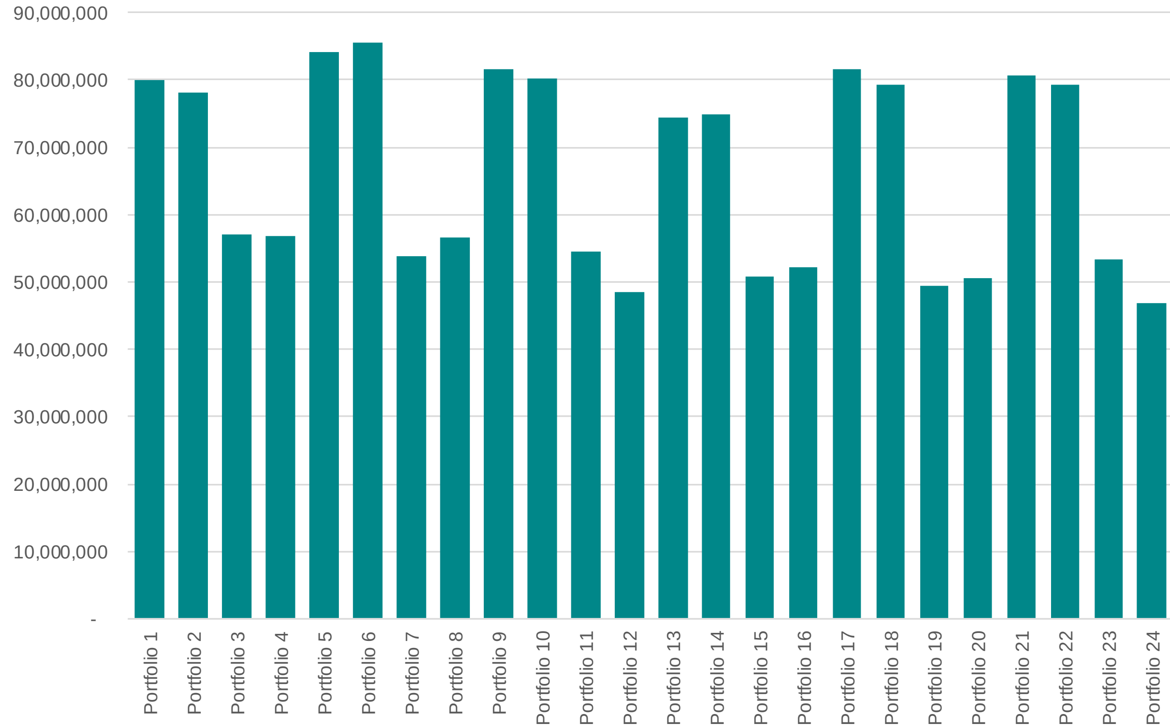
Lastly, Idaho Power reviewed recent system operations, resource dispatch and associated carbon emissions as well as the near-term operational forecasts. This review resulted in an Market Forecast Volatility adjustment to reconcile the discrepancy in emissions forecasts between the IRP and near-term operational planning. Examples of events that may drive market volatility: unplanned system outages (Idaho Power's system and surrounding system), extreme weather events, supply interruptions or limitations, natural disaster, etc.

Year	Resource CO_2 Emissions	Market Purchases CO_2	Hydro Policy Implementation Uncertainty Adjustment	Market Volatility Adjustment	Total System CO_2 Emissions	Oregon CO_2 Emissions
2019	4,100,667	287,475	329,686	190,859	4,908,687	223,856
2020	4,206,718	274,662	481,180	190,859	5,153,420	234,266
2021	4,165,188	350,488	541,259	190,859	5,247,795	237,805
2022	4,423,053	349,999	566,011	190,859	5,529,922	249,326
2023	3,932,304	436,275	586,927	190,859	5,146,365	230,902
2024	3,932,231	535,493	609,505	190,859	5,268,088	234,467
2025	4,323,190	524,129	617,935	190,859	5,656,114	250,654
2026	3,935,017	792,624	626,016	–	5,353,657	236,474
2027	3,535,890	879,349	631,418	–	5,046,658	222,285
2028	3,538,173	1,003,592	637,980	–	5,179,745	227,147
2029	2,345,650	1,480,651	643,882	–	4,470,182	195,093
2030	2,610,779	933,734	646,328	–	4,190,841	182,229
2031	1,687,670	1,432,465	651,605	–	3,771,741	163,443
2032	1,610,320	1,506,697	659,269	–	3,776,286	163,062
2033	1,671,532	1,599,885	672,911	–	3,944,327	169,880
2034	1,678,076	1,610,612	682,302	–	3,970,991	170,314
2035	1,848,815	1,527,210	693,035	–	4,069,059	173,587
2036	1,843,975	1,588,386	708,991	–	4,141,353	175,661
2037	1,833,284	1,550,450	687,647	–	4,071,380	171,707
2038	1,787,418	998,475	678,607	–	3,464,501	145,355

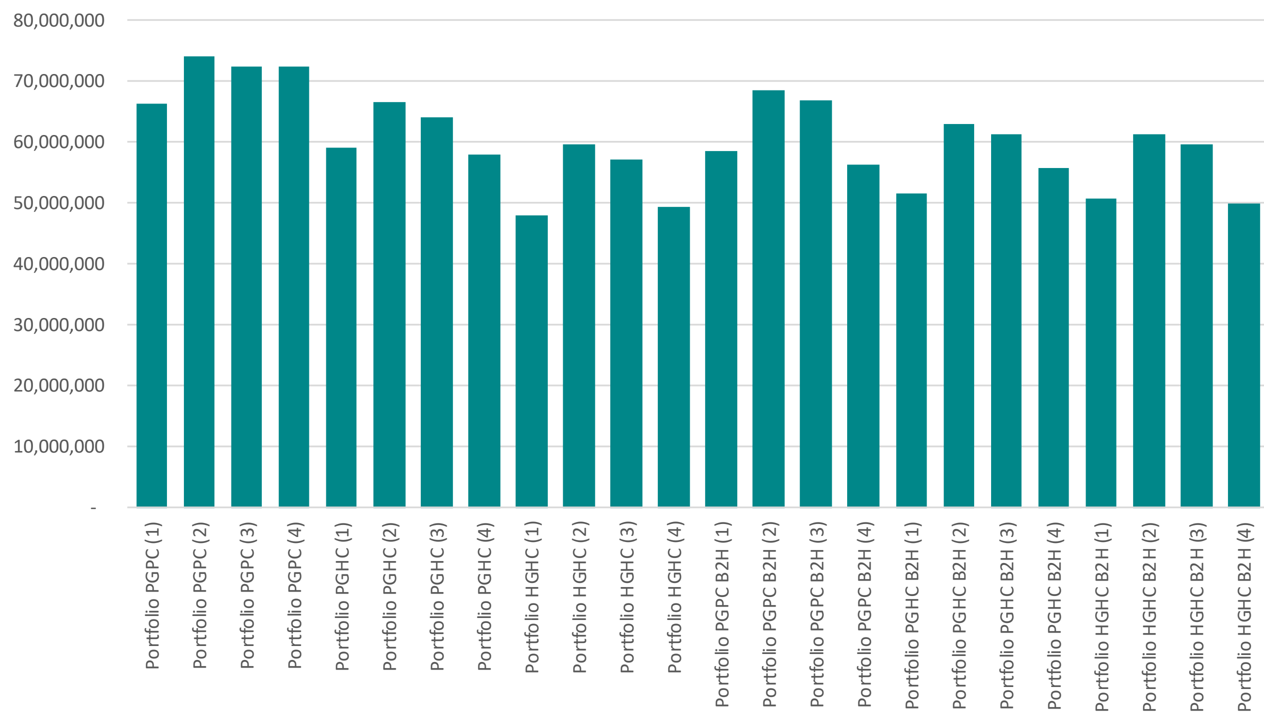
PORTFOLIO GENERATING RESOURCE EMISSIONS

CO_2 Tons

WECC-Optimized Portfolios

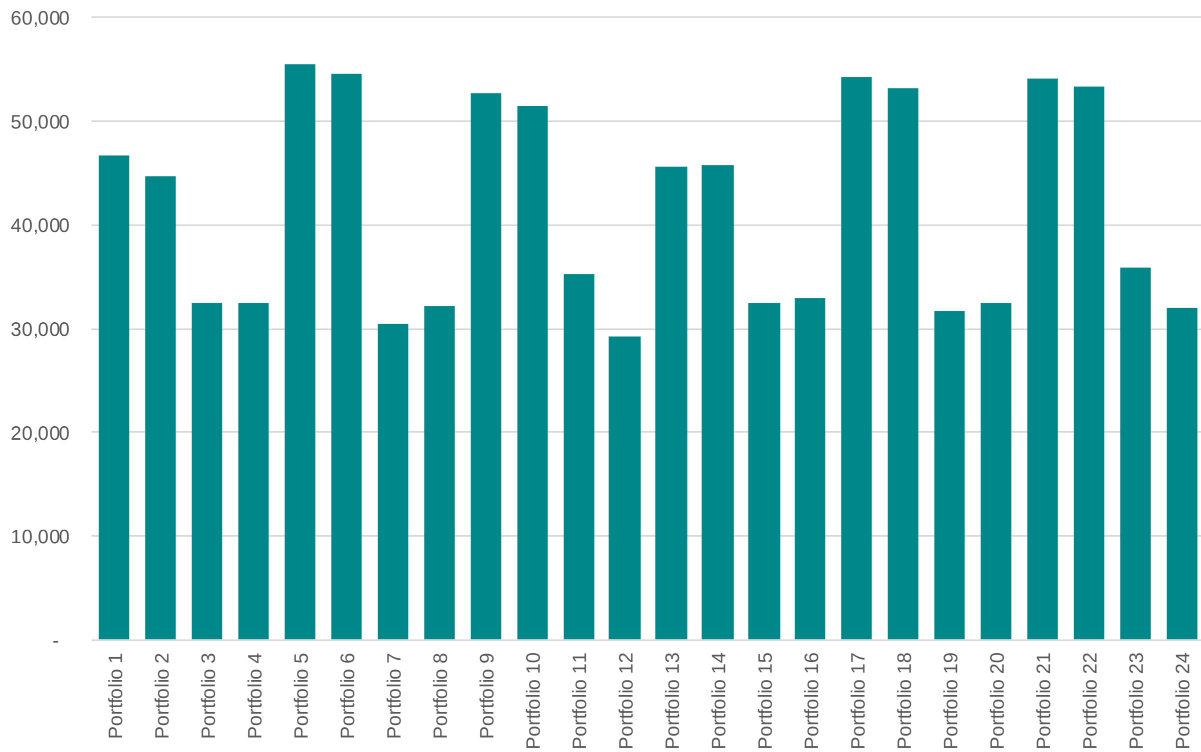


Idaho Power-Specific Portfolios

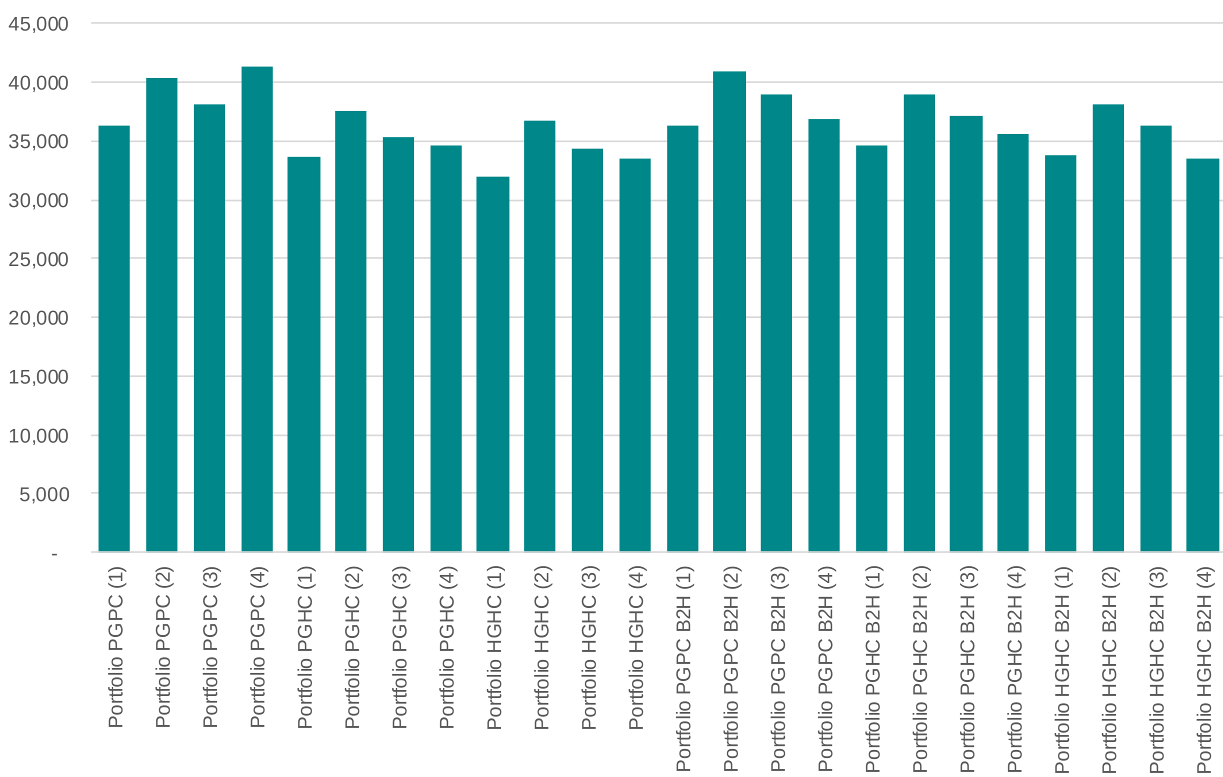


NOx Tons

WECC-Optimized Portfolios

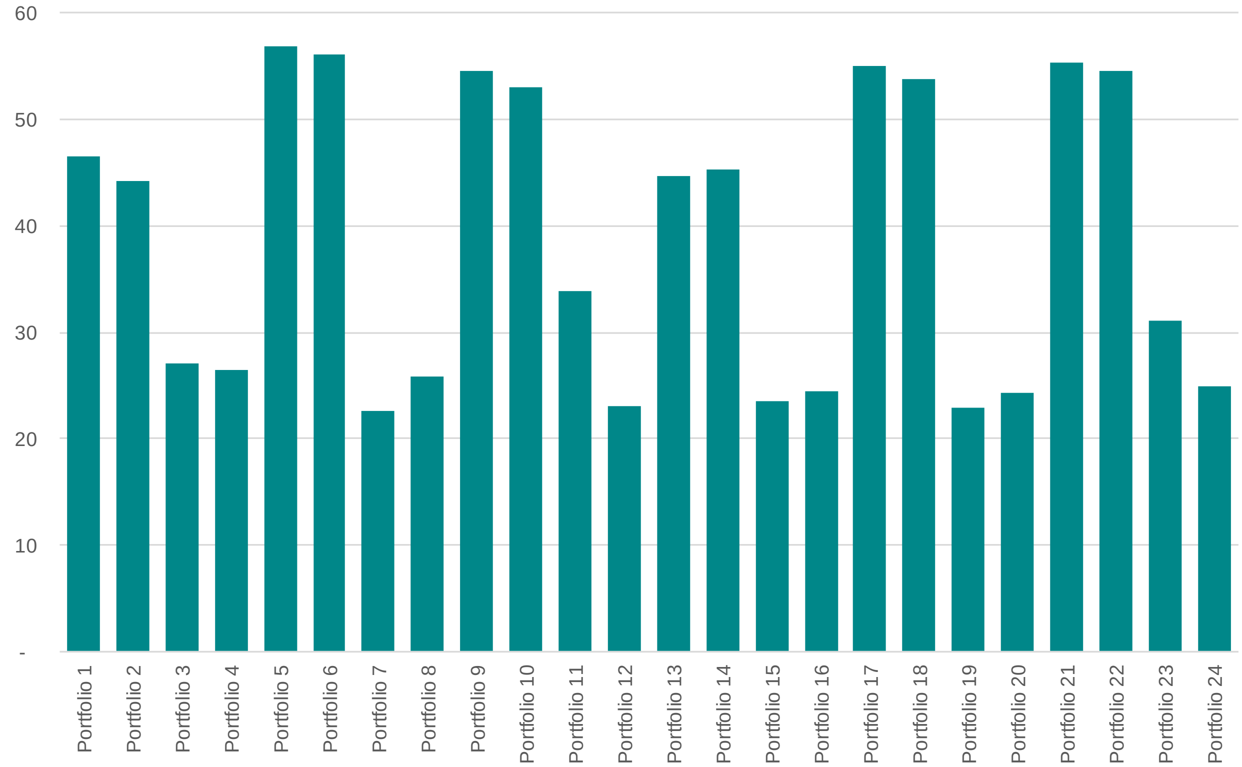


Idaho Power-Specific Portfolios

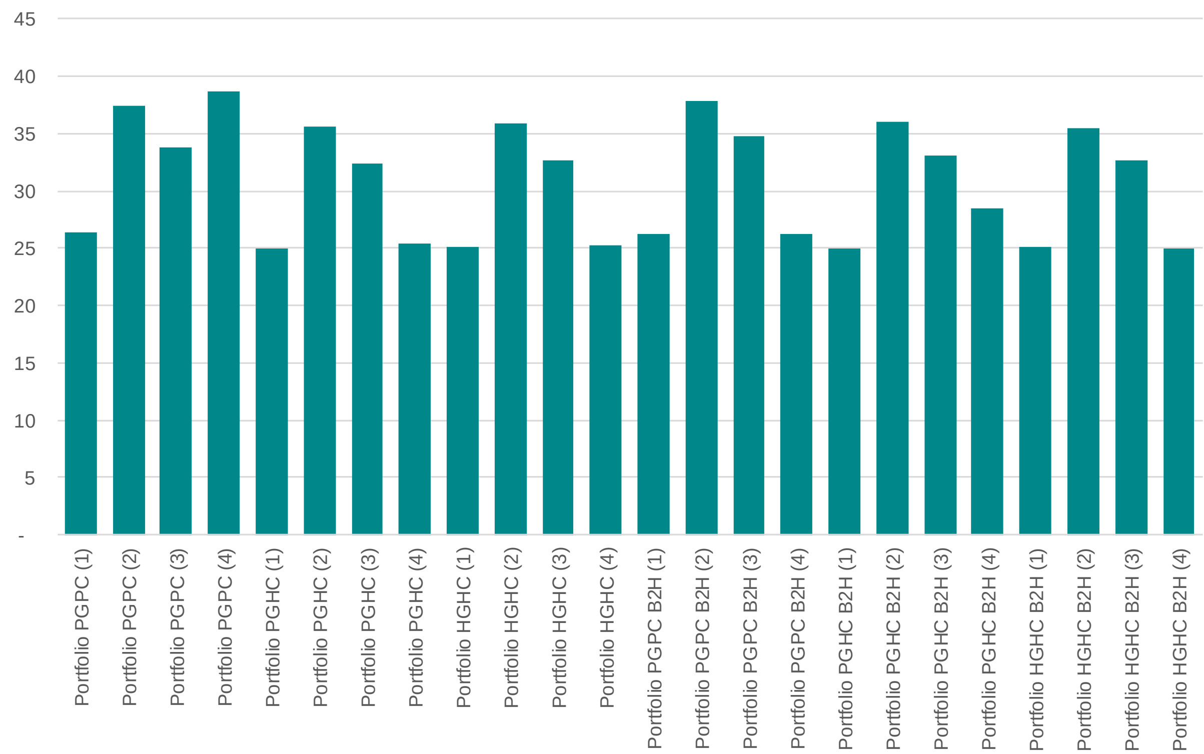


HG Tons

WECC-Optimized Portfolios

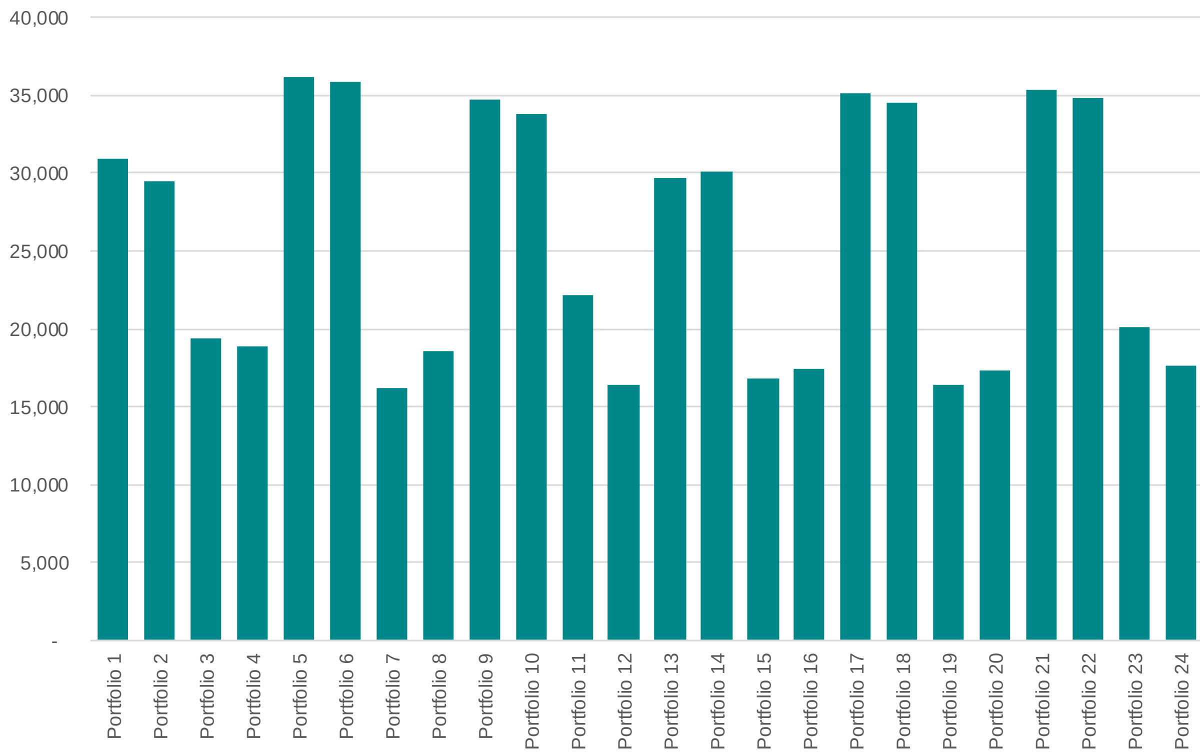


Idaho Power-Specific Portfolios

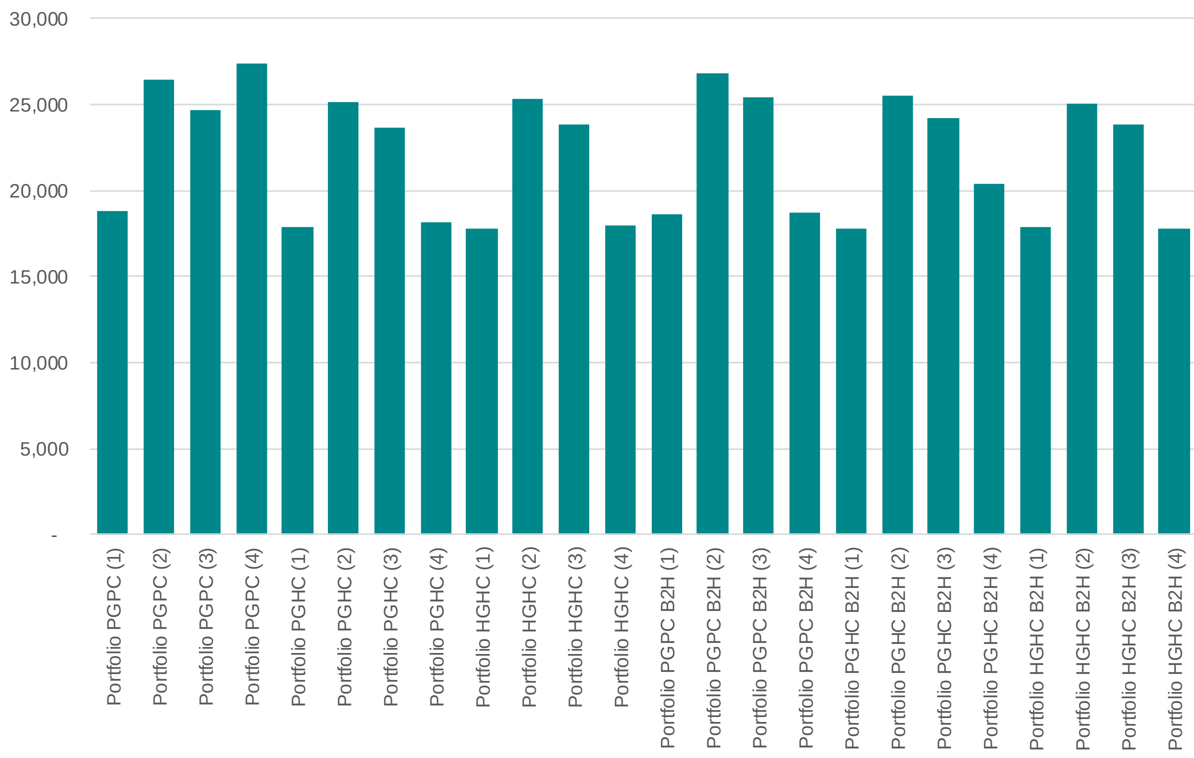


SO_2 Tons

WECC-Optimized Portfolios



Idaho Power-Specific Portfolios



Compliance with State of Oregon IRP Guidelines

Compliance with State of Oregon EV Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluation on a consistent and comparable basis.
   - All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of poweror gas purchases, transportation, and storageand demand side options which focus on conservation and demand response.
   - Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.

Idaho Power response:

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 3. Idaho Power Today;* demand-side options are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning*.

New resource options including fuel types, technologies, lead times, in-service dates, durations and locations are described in *Chapter 4. Future Supply-side Generation and Storage Resources*, *Chapter 5. Demand-Side resources*, *Chapter 6. Transmission Planning*, and *Chapter 7. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and *Chapter 9. Modeling Analysis and Result—Planning Case Portfolio Analysis*.

The WACC rate used to discount all future resource costs is discussed in the Technical Appendix *Supply Side Resource Data – Key Financial and Forecast Assumptions*.

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b. Risk and uncertainty must be considered.
   - At a minimum, utilities should address the following sources of risk and uncertainty:
     1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.
     2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.
   - Utilities should identify in their plans any additional sources of risk and uncertainty.

Idaho Power response:

Electric utility risk and uncertainty factors (load, natural gas, and water conditions) for resource portfolios are considered in *Chapter 9 Modeling Analysis*. Plant forced outages are modeled in AURORA on a unit basis and are discussed in *Chapter 9 Loss of Load Expectation*. Risk and uncertainty associated with high natural gas and high carbon cost are discussed in *Chapter 9 Portfolio Cost Analysis.*

Additional sources of risk and uncertainty including regional resource adequacy and qualitative risks are discussed in *Chapter 9. Modeling Analysis*.

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.
   - Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.
   - To address risk, the plan should include, at a minimum:
     a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
     b. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.
   - The utility should explain in its plan how its resource choices appropriately balance cost and risk.

Idaho Power response:

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. Summary—Introduction*.

Modeling analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases is discussed in *Chapter 9. Modeling Analysis*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis*.

Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1. IRP Methodology*. Idaho Power's Energy Risk Management Program is designed to systematically identify, quantify and manage the exposure of the company and its customers to the uncertainties related to the energy markets in which the Company is an active participant. The Company's Risk Management Standards limit term purchases to the prompt 18 months of the forward curve.

Idaho Power's plan and how the resource choices appropriately balance cost and risk is presented in *Chapter 10. Preferred Portfolio and Action Plan.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Idaho Power response:

Long-run public interest issues are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*.

Guideline 2: Procedural Requirements

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.

Idaho Power response:

The IRP Advisory Council meetings are open to the public. A roster of the IRP Advisory Council members along with meeting schedules and agendas is provided in the Technical Appendix, *IRP Advisory Council*.

b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

Idaho Power response:

Idaho Power makes public extensive information relevant to its resource evaluation and action plan. This information is discussed in IRP Advisory Council meetings and found throughout the 2019 IRP, the 2019 Load and Sales Forecast and in the 2019 Technical Appendix.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Idaho Power response:

Idaho Power provided copies to members of the IRPAC on Friday, June 7, 2019. The company requested for comments to be provided no later than Friday, June 14, 2019.

Guideline 3: Plan Filing, Review, and Updates

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.

Idaho Power response:

The OPUC acknowledged Idaho Power's 2017 IRP on May 23, 2018 in Order 18-176. The Idaho Power 2019 IRP will be filed by June 30, 2019.

b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

Idaho Power response:

Idaho Power will present the results of the Second Amended 2019 IRP at a ~~schedule a~~ public meeting at the OPUC ~~following the June 28, 2019 filing of the 2019 IRP~~on October 22, 2020.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

Idaho Power response:

No response needed.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

Idaho Power response:

No response needed.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

Idaho Power response:

No response needed.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

Idaho Power response:

Idaho Power submitted its annual update on January 28, 2019. A public meeting was held March 12, 2019 to discuss the 2017 IRP update.

g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:
   - Describes what actions the utility has taken to implement the plan;
   - Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and
   - Justifies any deviations from the acknowledged action plan.

Idaho Power response:

No response needed.

Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements;

Idaho Power response:

Idaho Power provides information on how the company met each requirement in a table is presented in the Technical Appendix and will be provided to the OPUC staff in an informal letter.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

Idaho Power response:

High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in *Chapter 7. Planning Period Forecasts*. Stochastic load risk analysis and major assumptions are discussed in *Chapter 9. Modeling Analysis*. Major assumptions are also discussed in *Chapter 7. Planning Period Forecasts.*

c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;

Idaho Power response:

Peaking capacity and energy capability for each year of the plan for existing resources is discussed in *Chapter 7. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Sales and Load Forecast Data* and *Existing Resource Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 8. Portfolios*.

d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;

Idaho Power response:

Not applicable.

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

Idaho Power response:

Supply-side resources are discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources*.

Demand-side resources are discussed in *Chapter 5-Demand-Side Resources*.

Resource costs are discussed in *Chapter 7. Planning Period Forecasts – Analysis of IRP ResourceResource Costs-IRP Resources* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*.

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

Idaho Power response:

Resource reliability is covered in *Chapter 9. Modeling Analysis*

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

Idaho Power response:

Key Assumptions including the natural gas price forecast are discussed in *Chapter 7. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in *Chapter 9. Modeling Analysis – Portfolio Emission Results* and in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*.

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

Idaho Power response:
Resource portfolios considered for the 2019 IRP are described in *Chapter 8. Portfolios*.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

Idaho Power response:
Evaluation of the portfolios over a range of risks and uncertainties is discussed in *Chapter 9. Modeling Analysis*.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

Idaho Power response:
Portfolio cost, risk results, interpretations and the selection of the preferred portfolio are provided in *Chapter 9. Modeling Analysis*.

k. Analysis of the uncertainties associated with each portfolio evaluated;

Idaho Power response:
The quantitative and qualitative uncertainties associated with each portfolio are evaluated in *Chapter 9. Modeling Analysis*.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

Idaho Power response:
The preferred resource portfolio is identified in *Chapter 10. Preferred Portfolio and Action Plan*.

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

Idaho Power response:

Risk associated with the selected portfolio including coal-unit exits is discussed in *Chapter 10. Preferred Portfolio and Action Plan*.

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Idaho Power response:

An action plan is provided in *Chapter 1. Summary—Action Plan* and in *Chapter 10 Preferred Portfolio and Action Plan.*

Guideline 5: Transmission

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

Idaho Power response:

The fuel transportation for each resource being considered is presented in the Technical Appendix, *Cost Inputs and Operating Assumptions*. Transmission assumptions for supply-side resources considered are included in *Chapter 6. Transmission Planning—Transmission assumptions in IRP portfolios*. Transportation for natural gas is discussed in *Chapter 7. Planning Period Forecasts—Natural Gas Price Forecast*.

Guideline 6: Conservation

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.

Idaho Power response:

The contractor-provided conservation potential study for the 2019 IRP and is described in *Chapter 5 Demand-Side Resources – Energy Efficiency Forecasting – Potential Assessment*.

b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

Idaho Power response:

A forecast for energy efficiency effects is provided in Cha*pter 5. Demand-Side Resources*.

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:
   - Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and
   - Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.

Idaho Power response:

Idaho Power administers all its conservation programs except market transformation. Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Appendix B: Idaho Power's Demand-Side Management 2017 Annual Report.* NEEA savings are included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.

Guideline 7: Demand Response

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Idaho Power response:

Demand response resources are evaluated in *Chapter 5. Demand-Side Resources – Changes from the 2017 IRP.*

Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Idaho Power response:

Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio are shown in the Technical Appendix, *Portfolio Analysis, Results, and Supporting Documentation*.

Guideline 9: Direct Access Loads

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Idaho Power response:

Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads.

Guideline 10: Multi-state Utilities

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Idaho Power response:

Idaho Power's analysis was performed on an integrated-system basis discussed in *Chapter 9. Modeling Analysis and Results*. Idaho Power will file the 2019 IRP in both the Idaho and Oregon jurisdictions.

Guideline 11: Reliability

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Idaho Power response:

The capacity planning margin and regulating reserves are discussed in Chapter 8. Portfolios. A loss of load expectation analysis and regional resource adequacy are discussed in *Chapter 9. Modeling Analysis.*

Guideline 12: Distributed Generation

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Idaho Power response:

Distributed generation technologies were evaluated in *Chapter 4. Future Supply-Side Generation and Storage Resources* and in *Chapter 7. Planning Period Forecasts—Analysis of IRP Resources*.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:
   - Identify its proposed acquisition strategy for each resource in its action plan.

- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

Idaho Power response:

Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the rules established by Oregon in Order No. 18-324 issued on August 30, 2018 and codified in Oregon Administrative Rules 860-089-0010-0550.

Idaho Power identifies its proposed acquisition strategy in *Chapter 10. Preferred Portfolio and Action Plan—Action Plan (2019–2026).* Discussion of asset ownership versus market purchases is found in *Chapter 9. Modeling Analysis*.

b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.

Idaho Power response:

Not applicable.

Compliance with EV Guidelines

Guideline 1: Forecast the Demand for Flexible Capacity

Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

Idaho Power response:

A discussion of the 2019 IRP's analysis for the flexibility guideline is provided in *Chapter 8. Portfolios.*

Guideline 2: Forecast the Supply for Flexible Capacity

Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;

Idaho Power response:

A discussion of the planning margin and regulating reserves is found at *Chapter 8. Portfolios.*

Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis

In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Idaho Power response:

The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast, *Company System Load—Electric Vehicles.*

State of Oregon Action Items Regarding Idaho Power's 2017 IRP

Action Item 1: EIM

Continue planning for western EIM participation beginning in April 2018.

Idaho Power response:

Idaho Power joined the western EIM in April 2018.

Action Item 2: Loss-of-load and solar contribution to peak

Investigate solar PV contribution to peak and loss-of-load probability analysis.

Idaho Power response:

Solar PV contribution to peak is discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources – Renewable Resource – Solar*.

Loss-of-load probability analysis is discussed in *Chapter 9. Modeling Analysis – Loss of Load Expectation.*

Action Item 3: North Valmy Unit 1

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.

Idaho Power response:

Idaho Power's action plan continues to target 2019 as the exit date from North Valmy Unit 1. Idaho Power's exit from Valmy Unit 1 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

The assessment of import dependability from northern Nevada is discussed in *Chapter 6. Transmission Planning – Nevada without North Valmy.*

Action Item 4: Jim Bridger Units 1 and 2

Plan and negotiate with PacifiCorp and regulators to achieve earl retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.

Idaho Power response:

Idaho Power's 2019 IRP Action Plan is detailed in Chapter 10. Action Plan (2019-2026) and includes updated target dates for early exits during 2022 and 2026. Discussion of the modeling analysis to reach these target dates is at *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources-Coal Resources – Jim Bridger.* Discussion of risks related to these planning and negotiating actions is discussed in *Chapter 9. Modeling Analysis – Qualitative Risk Analysis.*

Action Item 5: B2H

Conduct ongoing permitting, planning studies, and regulatory filings.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 6: B2H

Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 7: Boardman

Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.

Idaho Power response:

Idaho Power's action plan continues to target 2020 as the exit date from Boardman. Idaho Power's exit from Boardman is discussed in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – Boardman*.

Action Item 8: Gateway West

Conduct ongoing permitting, planning studies, and regulatory filings.

Modifications: Idaho Power should provide additional information to the Commission on an ongoing basis on Energy Gateway's progress, Idaho Power's inclusion of it as a least-cost/least risk portfolio, the status of co-participants and Energy Gateway's role in the IRP.

Idaho Power response:

Discussion regarding Gateway West is found in *Chapter 6. Transmission Planning – Gateway West*.

Idaho Power files quarterly transmission updates regarding the Energy Gateway West transmission project and updates on the permitting or completion of the Boardman to Hemingway transmission line project with the OPUC in Docket RE 136. The transmission update for Q4 2018 was filed on January 15th, 2019 and the update for Q1 2019 was filed on April 30, 2019.

Action Item 9: Energy Efficiency

Continue the pursuit of cost-effective energy efficiency.

Modifications: In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology.

Idaho Power response:

Idaho Power's energy efficiency opportunities and improvements to its avoided cost methodology are discussed in *Chapter 5. Demand-side Resources*.

Action Item 10: Carbon emission regulations

Continue stakeholder involvement in CAA Section 111(d) proceeding, or alternative regulations affecting carbon emissions.

Modifications: Idaho Power will provide a report as part of its 2019 IRP filing describing the risks to the company and its customers associated with climate change.

Idaho Power response:

Idaho Power continues to participate in carbon emission discussions and announced our Clean Energy Goal in March 2019. These efforts are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*. Modeling of carbon regulation is discussed *in Chapter 8. Portfolios – Framework for Expansion Modeling – Carbon Price Forecasts*.

Action Item 11: North Valmy Unit 2

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operation by year-end 2025.

Idaho Power response:

Idaho Power's exit from Valmy Unit 2 is discussed in *Chapter 1. Summary – Action Plan – Valmy Unit 2 Exit Date*.

Other Item 1: 2019 IRP Preview

Idaho Power is required that five months prior to the filing of the 2019 IRP, Idaho Power file a report in this docket providing the following information:

- Comprehensive update of the B2H project.
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast.
- A discussion of portfolio modeling options and preferences for the 2019 IRP.
- An update on Jim Bridger environmental control developments and options.
- Updates as requested by Staff.

Idaho Power response:

Idaho Power's filed the updated IRP Report with the OPUC on January 28, 2019.

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INTEGRATED RESOURCE PLAN

2019

SECOND AMENDED—REDLINE

OCTOBER • 2020

APPENDIX D: B2H SUPPLEMENT

SAFE HARBOR STATEMENT

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

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EXECUTIVE SUMMARY

The Boardman to Hemingway Transmission Line Project (B2H) is a planned 500-kilovolt (kV) transmission project that would span between the Hemingway 500-kV substation near Marsing, Idaho, and the proposed Longhorn Station near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. Idaho Power's planned capacity interest in B2H will increase the availability of capacity and energy from the Pacific Northwest market by 500 megawatts (MW) during the summer months, when energy demand from Idaho Power's customers is at its highest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's integrated resource plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the 2019 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new combined-cycle gas plant, or a new utility-scale solar complex.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. As can be seen in the *Second Amended 2019 IRP*, the lowest-cost resource portfolio includes B2H. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational flexibility.

In addition to being the least-cost, lowest-risk resource to meet Idaho Power' resource needs, the B2H project has received national recognition for the benefits it will provide. 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. Most recently, B2H was acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,[1] B2H was held up as a "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…" The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.

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

Under the B2H Permit Funding agreement, Idaho Power is ~~allocated a~~funding 21.2-percent of the permitting costs for the project~~ interest~~, with PacifiCorp and Bonneville Power Administration (BPA) ~~subscribed for~~funding the remainder of ~~the line's capacity. The agreement~~those costs. With permitting nearing completion, the three entities are currently negotiating potential construction and ownership agreements to complete the project. Working with coparticipants will allow Idaho Power customers to benefit from the project's economies of scale and from load diversity between the ~~project~~ coparticipants. While Idaho Power's 21.2-percent share would provide for an annual average of 350 MW of west-to-east import capacity, the agreement is structured to provide Idaho Power with 500 MW of import capacity during the summer months, when Idaho Power experiences peak demand, and 200 MW of import capacity in the winter months, when the load-serving need is less.

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20 percent contingency for unforeseen expenses. In the *Second Amended 2019 IRP*, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million in B2H project expenses. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly 10 years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017. The BLM ROD formalized the conclusion of the siting process at the federal level, as required by the *National Environmental Policy Act of 1969* (NEPA). The BLM ROD provides the ability to site the B2H project on BLM-administered land. Idaho Power also received a ROD from the U.S. Forest Service in 2018 and a ROD from the U.S. Navy in 2019.

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy in summer 2017~~ and~~. The Oregon Department of Energy issued a ~~Draft~~ Proposed Order on ~~May 22, 2019.~~July 2, 2020 that recommends approval of the project to Oregon's Energy Facility Siting Council (EFSC~~)~~). Following the Proposed Order, the EFSC will conduct a contested case proceeding on the Proposed Order. The EFSC is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[2] Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be

[2] See generally Oregon Revised Statute (ORS) 469.300-469.563, 469.590-469.619, and 469.930-469.992.

established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based in part on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company's IRP.[3] ~~Similar to~~The OPUC has already acknowledged the construction of B2H in Idaho Power's 2017 IRP. In this case, Idaho Power again seeks to ~~satisfy EFSC's least-cost plan rule requirement through an~~ confirm its acknowledgement of ~~its~~ B2H as reflected in the *Second Amended 2019 IRP*.

As of the date of this report, Idaho Power expects the Oregon Department of Energy (ODOE) to issue a Final Order and Site Certificate in 2021. To achieve ~~an~~a 2026 in-service date, as shown in the ~~mid-2020s~~near-term Action Plan, preliminary construction activities must commence in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) acquisition activities, and detailed design and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

This B2H appendix to the *Second Amended 2019 IRP* provides context and details that support evaluating this transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

[3] OAR 345-023-0020(2). Idaho Power is also requesting satisfaction of the need standard under EFSC's System Reliability Rule, OAR 345-023-0030.

Resource Need Evaluation

Resource Needs and Capacity Expansion Modeling

A 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 which were quantifiably demonstrated to eliminate the identified resource deficiencies, and qualitatively varied by resource type, where the varied resource types considered reflected the company's understanding that the financial performance of a resource class is dependent on future conditions in energy markets and energy policy.

Idaho Power received comments on the 2017 IRP encouraging the use of capacity expansion modeling for *Second Amended 2019 IRP* portfolio development. In response to this encouragement, the company elected to use the AURORA model's capacity expansion modeling capability to develop portfolios for the *Second Amended 2019 IRP*. Under this process, the alternative future scenarios are formulated first, and then the AURORA model is used to develop portfolios that are optimal to the selected alternative future scenarios. For example, the AURORA model can be expected under an alternative future scenario having high natural gas price and/or high cost of carbon to develop a portfolio having substantial expansion of non-carbon emitting variable energy resources, as such a portfolio is likely well fit for such a scenario.

The use of capacity expansion modeling has resulted in a departure from the 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 *Second Amended 2019 IRP*, the AURORA model selects from the variety of supply- and demand-side resource options available to it to develop portfolios that are optimal for the given alternative future scenarios with the objective of meeting a 15 percent planning margin and regulating reserve requirements associated with balancing load, wind plant output, and solar plant output. The model can also simulate retirement of existing generation units if economical as well as build resources that are economic absent a defined capacity need. The capacity expansion modeling process is discussed in further detail in Chapter 8 of Idaho Power's *Second Amended 2019 IRP*.

In meeting the objectives for planning margin and regulating reserve requirements, the AURORA model accounts for the capability of the existing system to meet the objectives and only selects from the pool of new supply- and demand-side resource options 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, such as that provided by B2H. Existing demand-side resources include current levels of demand response and savings from current energy efficiency programs and measures.

IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the Public Utility Commission of Oregon (OPUC) adopted guidelines regarding integrated resource planning.[4]

> Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation *and electric transmission facilities as resource options*, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving *reliability*.

Boardman to Hemingway as a Resource

The Boardman to Hemingway Transmission Line Project (B2H) is one of the most cost-effective IRP resources Idaho Power has considered as proven through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the capacity cost of the project (capital and other fixed costs) and 2) the energy cost of the project (variable costs). Capital costs are derived through cost estimates to install the various projects. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc.

Illustrating the difference between capacity and energy, a diesel generator may have a very low cost to install; however, the cost of diesel fuel and the maintenance required would be significant. Alternatively, a utility-scale solar plant will have almost no energy cost; the fuel to run the plant—the sun—is free. However, in the case of a solar plant, the capacity cost to install the plant, while continuing its declining trend, can still be relatively expensive, particularly when considered in terms of cost per unit of *on-peak* capacity.

Capacity Costs

Table 1 below provides capital costs for resource options found in the *Second Amended 2019 IRP* to have the lowest cost from a capacity perspective. Capital costs in Table 1 are provided in base year 2023 dollars. The use of 2023 as base year allows the analysis to capture declining

[4] apps.puc.state.or.us/orders/2007ords/07-002.pdf

capital cost trends for solar resources. The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H.

Table 1. Total capital $/kW for select resources considered in the 2019 IRP (2023$)

Resource Type	Total Capital $/kW	Total Capital $/kw—peak	Depreciable Life
B2H	$894*	$626**	55 years
Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 megawatts [MW])	$1,294	$1,294	30 years
Simple-cycle combustion turbine — Frame F Class (170 MW)	$1,142	$1,142	35 years
Reciprocating Gas Engine (111.1 MW)	$1,087	$1,087	40 years
Solar Photovoltaic (PV)—Utility-Scale 1-Axis	$1,498	$3,329***	30 years

* Uses the B2H 350-MW average capacity
** Uses the B2H 500-MW capacity
***Uses on-peak capacity of 45 percent of installed nameplate capacity

The B2H total capital cost per kilowatt at peak is roughly 60 percent of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to at most 40 years for a gas plant or 30 years for a solar plant. The low up-front cost and slower depreciation further reduces the cost impact to Idaho Power's customers. Finally, the B2H cost estimate includes a 20 percent contingency, whereas none of the other resources evaluated in the *Second Amended 2019 IRP* includes a cost contingency. The summation of these factors suggest B2H is the lowest capital-cost resource by a substantial margin.

Energy Cost

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub~~.~~ at both peak times and when energy prices are favorable relative to the costs of Idaho Power's existing resource fleet. Referencing ~~Table~~Figure 7.6 in the *Second Amended 2019 IRP*, the B2H project has the lowest levelized cost of energy relative to other resource options evaluated in the *Second Amended 2019 IRP*.

Market Overview

Power Markets

A power market hub is an aggregation of transaction points (often referred to as bus points or buses). Hubs create a common point to buy and sell energy, creating one transaction point for bilateral transactions. Hubs also create price signals for geographical regions.

Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.
2. Reliable contractual standards exist for the delivery and receipt of the energy.
3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

Mid-C Market

The Mid-C electric energy market hub is a hub where power is transacted both physically and financially (derivative). Power is traded both physically and financially in different blocks: long term, monthly, balance-of-month, day ahead, and hourly. Much of the activity for balance-of-month and beyond is traded and cleared through a clearing exchange, the Intercontinental Exchange (ICE). For short-term transactions, such as day-ahead and real time (hourly), trades are made primarily between buyers and sellers negotiating price, quantity, and point of delivery over the phone (bilateral transactions). In the Pacific Northwest, most of the price negotiations begin with prices displayed for Mid-C on the ICE trading platform.

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 1 shows the relative volume of energy in the Northwest.

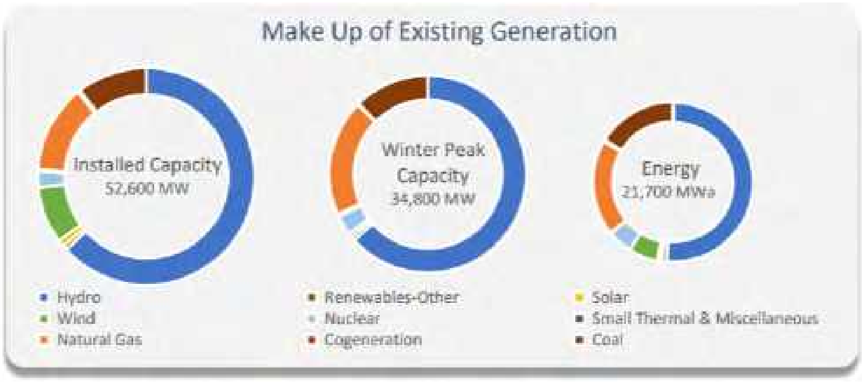

Figure 1. Northwest regional forecast (Source: 2017 PNUCC)[5]

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2018, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 10,000 megawatt-hours (MWh) to over 49,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 1,600,000 MWhs. These volumes are in addition to daily broker trades and month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following market participants transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Water and Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric

[5] pnucc.org/system-planning/northwest-regional-forecast

- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma Power

Energy traded at Mid-C is not necessarily physically generated in the Mid-Columbia River geographic area. For instance, Powerex is a merchant of BC Hydro in British Columbia and frequently buys and sells energy at Mid-C. A trade at Mid-C requires that transmission is available to deliver the energy to Mid-C. Transmission wheeling charges must be accounted for when transacting at Mid-C. Sellers at Mid-C must pay necessary transmission charges to deliver power to Mid-C, and buyers must pay necessary transmission charges to deliver power to load.

Mid-C and Idaho Power

Historically, Idaho Power wholesale energy transactions have correlated well with the Mid-C hub due to Idaho Power's proximity to the market hub and because it is the most liquid hub in the region. Energy at Mid-C can be delivered to, or received from, Idaho Power through a single transmission wheel through ~~the~~Avista, BPA, or ~~Avista~~PacifiCorp. Additionally, long-term monthly price quotes are readily available for Mid-C, making it an ideal basis for long-term planning.

Idaho Power uses the market to balance surplus and deficit positions between generation resources and customer demand, and to take advantage of price differences across the region. For example, when market purchases are more cost-effective than generating energy within Idaho Power's generation fleet, Idaho Power customers benefit from lower net power supply cost through purchases instead of Idaho Power fuel expense. Idaho Power customers also benefit from the sale of surplus energy. Surplus energy sales are made when Idaho Power's resources are greater than Idaho Power customer demand and when the incremental cost of these resources are below market prices. Idaho Power customers benefit from these surplus energy sales as offsets to net power supply costs through the power cost adjustment (PCA).

In 2018, Idaho Power averaged approximately 85,000 MWh of total Mid-C purchases in June and July. As stated previously, the average monthly volumes at Mid-C, on a day-ahead basis, were approximately 1,600,000 MWh. Based on these averages, Idaho Power's purchases represented about 5 percent of the total market volumes in June and July. At 5 percent of total market volume on average in June and July, Idaho Power represents a very small fraction of the Mid-C volume during the months when Idaho Power relies on Mid-C the most.

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

Modeling of the Mid-C Market in the IRP

As part of the IRP analysis, Idaho Power uses the AURORA model to derive energy prices at the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear fuel price, hydro conditions, etc. Refer to chapters 8 and 9 of the *Second Amended 2019 IRP* for more information on AURORA and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon.

Transmission wheeling rates and wheeling losses are included in the AURORA database and are part of the dispatch logic within the AURORA modeling. AURORA economically dispatches generating units, which can be located across any system in the West. All market energy purchases modeled in AURORA include these additional transmission costs and are included in all portfolios and sensitivities.

B2H Comparison to Other Resources

The *Second Amended 2019 IRP* provides an in-depth analysis of the B2H project compared to alternative resource options. Table 2 summarizes some of the high-level differences between B2H and other notable resource options.

Table 2. High-level differences between resource options

	B2H	Reciprocating engines	CCCT	Lithium batteries	1-axis solar PV
Intermittent renewable					✓
Dispatchable capacity providing	✓	✓	✓	✓	
Non-dispatchable (coincidental) capacity providing					✓
Balancing, flexibility providing	✓	✓	✓	✓	
Energy providing	✓	✓	✓	✓	✓
Variable costs (primary variable cost driver)	Mid-C market	Natural gas	Natural gas	Mid-C market	No variable costs
Capital costs	$626 per on-peak kW	$1,087-1,205 per kW/kW	$1,294/kW	$1,870-3,004 per kW	$3,329 per /on-peak kW
Fuel price risk		✓	✓		
Wholesale power market price risk	✓			✓	
Other	Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resource promotes stability in customer rates, benefit to regional grid, supports Idaho Power's clean energy goal, long-lead resource.	Scalable (modeled generators 18.8-MW nameplate), relatively short-lead resource, range driven by plant configuration.	Relatively short-lead resource, dispatchable, recent construction experience.	Uncertainty related to performance (e.g., # of lifetime cycles), dispatchable, scalable, potential for geographic dispersion, cost range driven by storage duration.	Renewable, clean, scalable (modeled plants 40-MW nameplate), diminishing on-peak contribution with expanded penetration, short-lead resource, intermittent.

Notes:

1. Provided capital costs are in nominal dollars assuming 2023 on-line date (i.e., 2023$).
2. Solar is not dispatchable but tends to produce at fairly high levels during summer periods of high customer demand. For the expressed capital cost per on-peak kW, the assumed on-peak capacity is 45 percent of installed capacity.
3. Lithium battery is a net energy consumer (roundtrip efficiency = 88 percent). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.
4. B2H capital-cost estimate includes a 20-percent contingency. No other resources include contingency. B2H and solar capital costs are expressed in terms of $/on-peak kW, where on-peak kW for B2H are based on 500-MW summer capacity and for solar is based on on-peak capacity equal to 45 percent of installed capacity.

Idaho Power's Transmission System

Idaho Power's transmission system is a key element to providing reliable, responsible, fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 6.1

of the *Second Amended 2019 IRP* and in Figure 2. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances, the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Columbia River, wind in Wyoming, solar in the desert southwest). For much of its history, Idaho Power has taken advantage of resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power fully utilizes the capacity of these lines. Additional transmission capacity is required to access resources to serve incremental increases in peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

Transmission lines are constructed and operated at different operating voltages depending on purpose, location, and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV, but these voltages will not be discussed further in this appendix; the focus of this appendix is on higher voltage transmission lines used for moving bulk electricity. The higher the voltage, the greater the capacity of the line, but also greater construction cost and physical size requirements.

The utility industry often compares transmission lines to roads and highways. Typically, lower-voltage transmission lines (138 kV) are used to facilitate delivery of energy to substations to serve load, like a two-lane highway, while high-voltage transmission lines are used for bulk transfer of energy from one region to another, like an interstate highway. Much like roads and highways, transmission lines can become congested. Depending on the capacity needs, economics, distance (higher voltages result in less losses over long distances), and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines are chosen.

Transmission Capacity Between Idaho Power and the Pacific Northwest

A transmission path is one or more transmission lines that collectively transmit power to/from one geographic area to another. Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW are on the Idaho to Northwest path (Western Electricity Coordinating Council [WECC] Path 14), and 80 MW are on the Montana–Idaho path (WECC Path 18). The Idaho to Northwest transmission path is comprised of three 230-kV lines, one 500-kV line, and one 115-kV line. The capacity limit on the path is established through a WECC rating process based on equipment overload ratings resulting from the loss of the most critical element on the transmission system. Collectively, these lines between Idaho and the Northwest have a transfer capacity rating that is greater than the individual rating of each line but less than the sum of the individual capacity ratings of each line. Figure 2 shows an overview of Idaho Power's high-voltage transmission system.

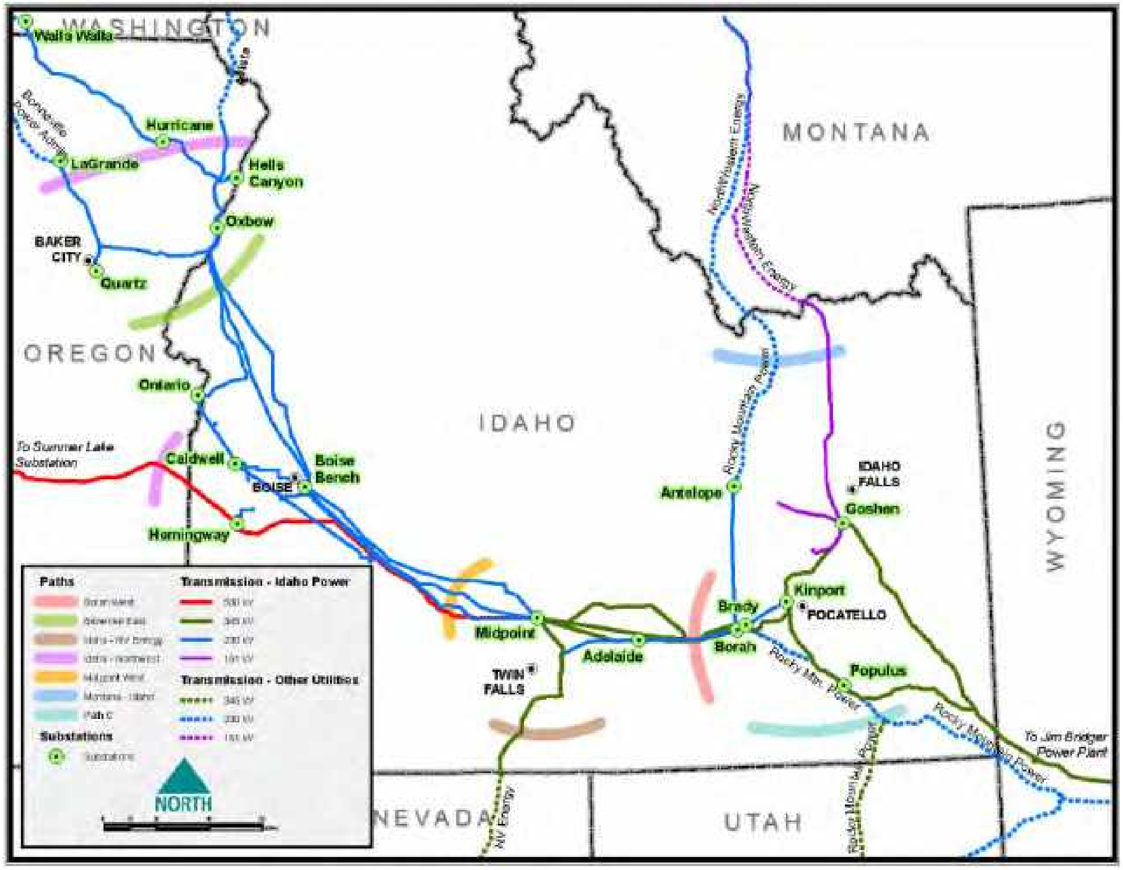

Figure 2. Idaho Power transmission system map

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2019. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load. Although Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest and Idaho Power's system, after all other uses are accounted for, Idaho Power will only able to use 304 MW to serve Idaho Power's native load in 2019. Idaho Power used 366 MW to serve BPA or PacifiCorp network load on Idaho Power's system, 280 MW were allocated to Transmission Reserve Margin (TRM), and 330 MW were allocated to Capacity Benefit Margin (CBM).

Table 3. Pacific Northwest to Idaho Power import transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	365
Boardman Generation	60
Fighting Creek (PURPA)	4
Pallette Load (PacifiCorp—Network Customer)	1
TRM	280
CBM	330
Subtotal	**1,040**
Pacific Northwest Purchase (Idaho Power Load Service)	240
Total	**1,280**

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability to ensure a safe and reliable transmission system. Idaho Power's TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loopflow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. However, physics dictate the actual power flow over the path (based on the path of least resistance), so actual flows don't equal contract-path schedules. The difference between scheduled and actual flow is referred to as unscheduled flow or loopflow. The average adverse loopflow across the Idaho to Northwest path during the month of July is 280 MW.

CBM is transmission capacity Idaho Power sets aside, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions. Idaho Power includes the 330 MW of CBM toward meeting a 15 percent planning margin.

Montana–Idaho Path Utilization

To utilize Idaho Power's share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 2 above.

Idaho to Northwest Path Utilization

To utilize Idaho Power's share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Table 4 details a typical summer allocation of the Idaho to Northwest capacity:

Table 4. The Idaho to Northwest Path (WECC Path 14) summer allocation

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

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

Avista, BPA and PacifiCorp share an allocation of capacity on the western side of the Idaho to Northwest path, and Idaho Power owns 100 percent of the capacity on the eastern side of the Idaho to Northwest path. For Idaho Power to transact across the path and serve customer load, Idaho Power's Load Servicing Operations must purchase transmission service from Avista, BPA, or PacifiCorp to connect the selling entity, via a contract transmission path, to Idaho Power.

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 500 MW in the summer months (April–September), and 200 MW in the winter months (January–March and October–December). A total breakdown of capacity rights of the B2H permitting coparticipants can be found in the Project Coparticipants section of this report. The Idaho to Northwest path is identified in Figure 2 above.

Regional Planning—Studies and Conclusions

~~The Northern Tier Transmission Group (NTTG) is a~~Idaho Power is currently a member of the NorthernGrid regional planning organization ~~that is organized and~~after joining in early 2020. NorthernGrid operates in compliance with FERC orders 890 and 1000.

Prior to joining NorthernGrid, Idaho Power was a member of and participated in the Northern Tier Transmission Group (NTTG) regional planning organization. The purpose of ~~NTTG~~regional planning is to consolidate each member's local transmission plans and determine a regional plan that can meet the needs of the combined member footprint in a more efficient or cost-effective manner. ~~Idaho Power is a member of and participates in the NTTG.~~

At NTTG, all member utilities ~~submit~~submitted their load forecasts, generation forecasts, and transmission needs. NTTG ~~studies~~studied the members' transmission footprints to determine the more efficient or cost-effective plan to meet those needs.

B2H ~~has been, and remains,~~was an integral part of NTTG's 10-year plan and in the 2018–2019 planning cycle, B2H was selected into the NTTG's Regional Transmission Plan. NTTG's analysis indicated B2H is the most cost-effective and efficient project to meet the needs of the NTTG footprint. The study noted that "Boardman to Hemingway resolved performance issues between the Northwest and Idaho under summer import conditions."[6]

~~In the 2018–2019 planning cycle, B2H was selected into the NTTG's Regional Transmission Plan.~~ For the most recent updates related to Idaho Power's regional planning organization, refer to the ~~NTTG~~NorthernGrid website at ~~.~~

~~The northwest has historically been represented by two regional planning organizations, NTTG and Columbia Grid. Idaho Power is participating in an effort to combine NTTG and Columbia Grid in to a single entity known as NorthernGrid. NorthernGrid will improve regional planning by including all Northwest utilities into a common regional planning organization. The formation of NorthernGrid is expected to be completed in early 2020~~northerngrid.net.

[6] NTTG 2018–2019 Regional Transmission Plan. nttg.biz

THE B2H PROJECT

Project History

The B2H project originated from Idaho Power's 2006 IRP. The 2006 IRP specified 285 MW of additional transmission capacity, increasing Idaho Power's connection to the Pacific Northwest power markets, as a resource in the preferred resource portfolio. A project had not been fully vetted at that time but was described as a 230-kV transmission line between McNary Substation and Boise. After the initial identification in the 2006 IRP, Idaho Power evaluated numerous capacity upgrade alternatives. Considering distance, cost, capacity, losses, and substation termination operating voltages, Idaho Power determined a new 500-kV transmission line between the Boardman, Oregon, area and the proposed Hemingway 500-kV substation would be the most cost-effective method of increasing capacity. Refer to Appendix D-1 for more information on the upgrade options considered.

Transmission capacity, especially at 500 kV, can be described as "lumpy" because capacity increments are relatively large between the different transmission operating voltages. In the 2009 IRP, Idaho Power assumed 425 MW of capacity, which was 50 percent of the assumed total rating. Idaho Power's long-standing preference was to find a partner or partners to construct B2H with to take advantage of economies of scale. In the 2011 IRP, Idaho Power assumed 450 MW of capacity. In 2012, Idaho Power achieved two major milestones: 1) PacifiCorp and BPA officially joined the B2H project as permitting coparticipants and 2) Idaho Power received a formal capacity rating for the B2H project via the WECC Path Rating Process (more on this process in preceding section). In the 2013 IRP, Idaho Power began to use the negotiated capacity from the permitting agreement: 500 MW in the summer and 200 MW in the winter, a yearly average of 350 MW, for a cost allocation of 21 percent of the total project. Idaho Power used the same 21.2 percent interest in the 2015, 2017 and 2019 IRPs.

Public Participation

The B2H project development has involved considerable stakeholder interaction over the last 12 years. Idaho Power has hosted and participated in over 275 public and stakeholder meetings with an estimated 4,500+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.

4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings. Additionally, numerous meetings with individuals and advocacy groups were held during and after the process.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report[7], and Idaho Power's initial scoping activities, visit the documents section[8] on the B2H website.

Throughout the BLM's NEPA process, including development of the Draft Environmental Impact Statement (EIS), issued Dec. 19, 2014, and prior to the Final EIS, issued Nov. 22, 2016, Idaho Power worked with landowners, stakeholders and jurisdictional leaders on route refinements and to balance environmental impacts with impacts to farmers and ranchers. For example, Idaho Power met with the original "Stop Idaho Power" group in Malheur County to help the group effectively comment and seek change from the BLM when the Draft EIS indicated a preference for a route across Stop Idaho Power stakeholder lands. BLM's decision was modified, and the route moved away from an area of highly valued agricultural lands in the Final EIS almost two years later.

Idaho Power worked with landowners in the Baker Valley, near the National Historic Oregon Trail Interpretive Center (NHOTIC), to move an alternative route along fence lines to minimize impacts to irrigated farmland, where practicable. This change was submitted by the landowners and included in the BLM's Final EIS and ROD (issued Nov. 17, 2017). Another change in Baker County was in the Burnt River Canyon and Durkee area, where Idaho Power worked with the BLM and affected landowners to find a more suitable route than what was initially preferred in the Draft EIS. Idaho Power is still working with landowners and local jurisdictional leaders to microsite in these areas to minimize impacts.

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize

[7] boardmantohemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf

[8] boardmantohemingway.com/documents.aspx

visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

However, Idaho Power worked with Umatilla County, local jurisdictional leaders and landowners to identify a new route through the entire county, essentially moving the line further south and away from residences, ranches, and certain agriculture. This southern route variation through Umatilla County was included the BLM's Agency Preferred route.

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all the noted parties in the local area. A major milestone was achieved when the U.S. Navy issued a Record of Decision for the proposed route in September 2019.

Finally, in Union County Idaho Power worked with local jurisdictional leaders, stakeholder groups, such as the Glass Hill Coalition and some members of StopB2H (prior to that group's formation) to identify new route opportunities. The Union County B2H Advisory Commission agreed to submit a route proposal to the BLM that followed existing high-voltage transmission lines, which was later identified as the Mill Creek Alternative. At the same time, Idaho Power met with a large landowner to adjust the Morgan Lake Alternative route to minimize impacts. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (referred to as the Glass Hill Alternative) by local landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its Application for Site Certificate filed with the Oregon Department of Energy in September 2018. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Mill Creek alternatives. As of the date of the filing of the *Second Amended 2019 IRP*, Idaho Power understands that the Morgan Lake route alternative is preferred by the local community.

Project Activities

Below is a summary of notable activities by year since project inception. For more information about any of the activities, please visit the B2H website.

2006

Idaho Power files its IRP with a transmission line to the Pacific Northwest identified in the preferred resource portfolio.

2007

Idaho Power analyzes the capacity and cost of different transmission line operating voltages and determines a new 500-kV transmission line to be the most cost-effective option to increase capacity and meet customer needs. Idaho Power files a Preliminary Draft Application for Transportation and Utility Systems and Facilities on Federal Lands. Idaho Power scopes routes.

2008

Idaho Power submits application materials to the BLM. Idaho Power submits a Notice of Intent to the EFSC. The BLM issues a Notice of Intent to prepare an EIS; officially initiating the BLM-led federal NEPA process. Idaho Power embarks on a more extensive public outreach program to determine the transmission line route.

2009

Idaho Power pauses NEPA and EFSC activities to work with community members throughout the route as part of the CAP to identify a proposed route that would be acceptable to both Idaho Power and the public. Forty-nine routes and/or route segments were considered through CAP.

2010

The CAP concludes. Idaho Power resubmits a proposed route to the BLM based on input from the CAP. The BLM re-initiates the NEPA scoping process and solicits public comments. Idaho Power publishes its B2H Siting Study. Idaho Power files a Notice of Intent with EFSC.

2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects[9].

2012

The ODOE conducts informational meetings and solicits comments. The ODOE issues a Project Order outlining the issues and regulations Idaho Power must address in its Application for Site Certificate. Additional public outreach and analysis resulted in route modifications and refinements submitted to the BLM. Idaho Power issues a Siting Study Supplement. Idaho Power conducts field surveys for the EFSC application. WECC adopts a new Adjacent Transmission Circuits definition with a separation distance of 250 feet, which would later modify routes in the EIS process. Idaho Power receives a formal capacity rating from WECC.

[9] boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf

2013

Public meetings are held. Idaho Power submits its Preliminary Application for Site Certificate to the ODOE. The BLM releases preliminary preferred route alternatives and works on a Draft EIS.

2014

The BLM issues a Draft EIS identifying an Agency Preferred Alternative. The 90-day comment period opens. Idaho Power conducts field surveys for EFSC application.

2015

The BLM hosts open houses for the public to learn about the Draft EIS, route alternatives, environmental analysis. The BLM reviews public comments. Idaho Power notifies the BLM of a preferred termination location, Longhorn Substation. Idaho Power submits an application to the Navy for an easement on the Naval Weapons System Training Facility in Boardman.
Idaho Power conducts field surveys for the EFSC application.

2016

Idaho Power submits a Draft Amended Application for Site Certificate to the ODOE for review. The BLM issues a Final EIS identifying an environmentally preferred route alternative and an Agency Preferred route alternative. Idaho Power incorporates the Agency Preferred route alternative into the EFSC application material. Idaho Power collaborates with local area stakeholders in Morrow County to find a routing solution on Navy-owned land. Idaho Power submits a revised application to the Navy. Idaho Power conducts field surveys for the EFSC application.

2017

Idaho Power submits an Amended Application for Site Certificate to the ODOE. The BLM issues a Record of Decision.

2018

ODOE and Idaho Power conduct public meetings after ODOE determined the Application for Site Certificate was complete. The Oregon PUC issues Order No. 18-176 in Docket No. LC 68 specifically acknowledging Idaho Power's 2017 Integrated Resource Plan and action items related to B2H. The U.S. Forest Service issues a Record of Decision. Idaho Power prepares and submits a Geotechnical Plan of Development to the BLM for approval.

2019

The U.S. Forest Service issues ROW easement. ODOE issues a Draft Proposed Order~~.~~ (DPO). The U.S. Navy issues a Record of Decision. BPA issues a ROD for moving the existing 69-kV line from Navy property to accommodate the B2H project. Idaho Power coordinates with BLM on Geotechnical Plan of Development. Preparations begin for issuing detailed design bid package.

2020

The U.S. Navy issues an easement for the B2H project. Based on the DPO, ODOE issues a Proposed Order and notice for Contested Case. Preparations begin for several pre-construction activities; which include completing LIDAR (aerial mapping) for the entire B2H project route and initiating detailed design. Additionally, Idaho Power is initiating the following activities for 2021: ROW acquisition, legal surveys, and geotechnical investigation.

For a detailed list of project activities by year, please refer to Appendix D-2.

Route History

As stated previously, the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500-kV line between the Boardman area and the Hemingway Substation. Several northern terminus substations were considered over the years, including the Boardman coal plant 500-kV yard, the proposed Grassland Substation to be constructed by Portland General Electric to integrate the then-proposed Carty Plant, and the proposed Longhorn Substation, which at the time was proposed by BPA to integrate wind onto the BPA 500-kV transmission system. During scoping, a considerable number of routes were considered to connect Hemingway and the Boardman area. Figure 3 is a snapshot of a number of routes considered early on during the CAP process (2009 timeframe). Numerous alternatives were considered, including routes through Idaho and through central Oregon. This large number of routes was further refined during the CAP process.

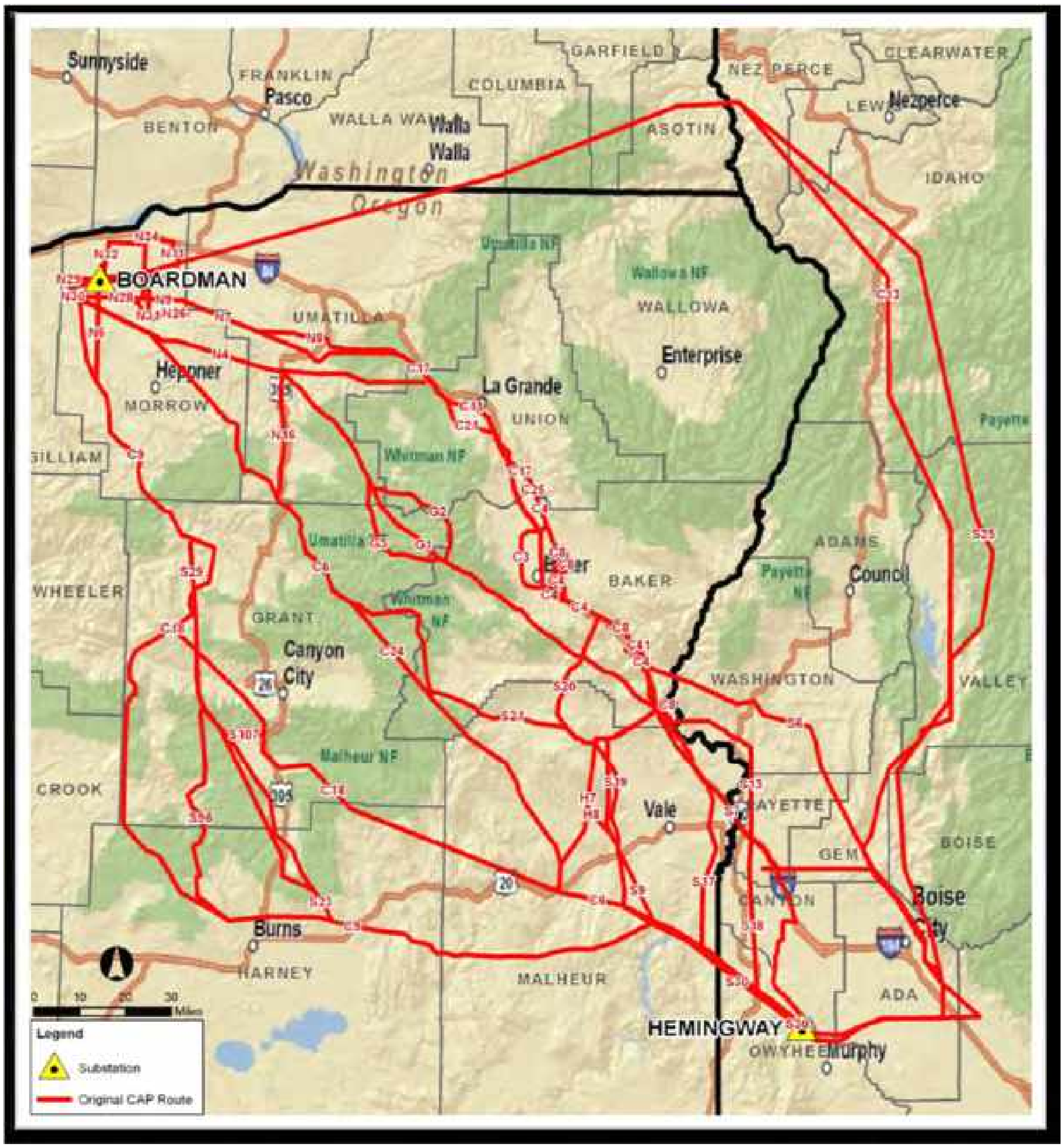

Figure 3. Routes developed by the Community Advisory Process teams (2009 timeframe)

The CAP process resulted in Idaho Power submitting the route shown in Figure 4 as the company's proposed route in the BLM-led NEPA process.

Figure 4. **B2H proposed route resulting from the Community Advisory Process (2010 timeframe)**

The BLM considered Idaho Power's proposed route, along with a number of other reasonable alternative routes, in the NEPA process. Figure 5 shows the route alternatives and variations considered in the BLM's November 2016 Final EIS.

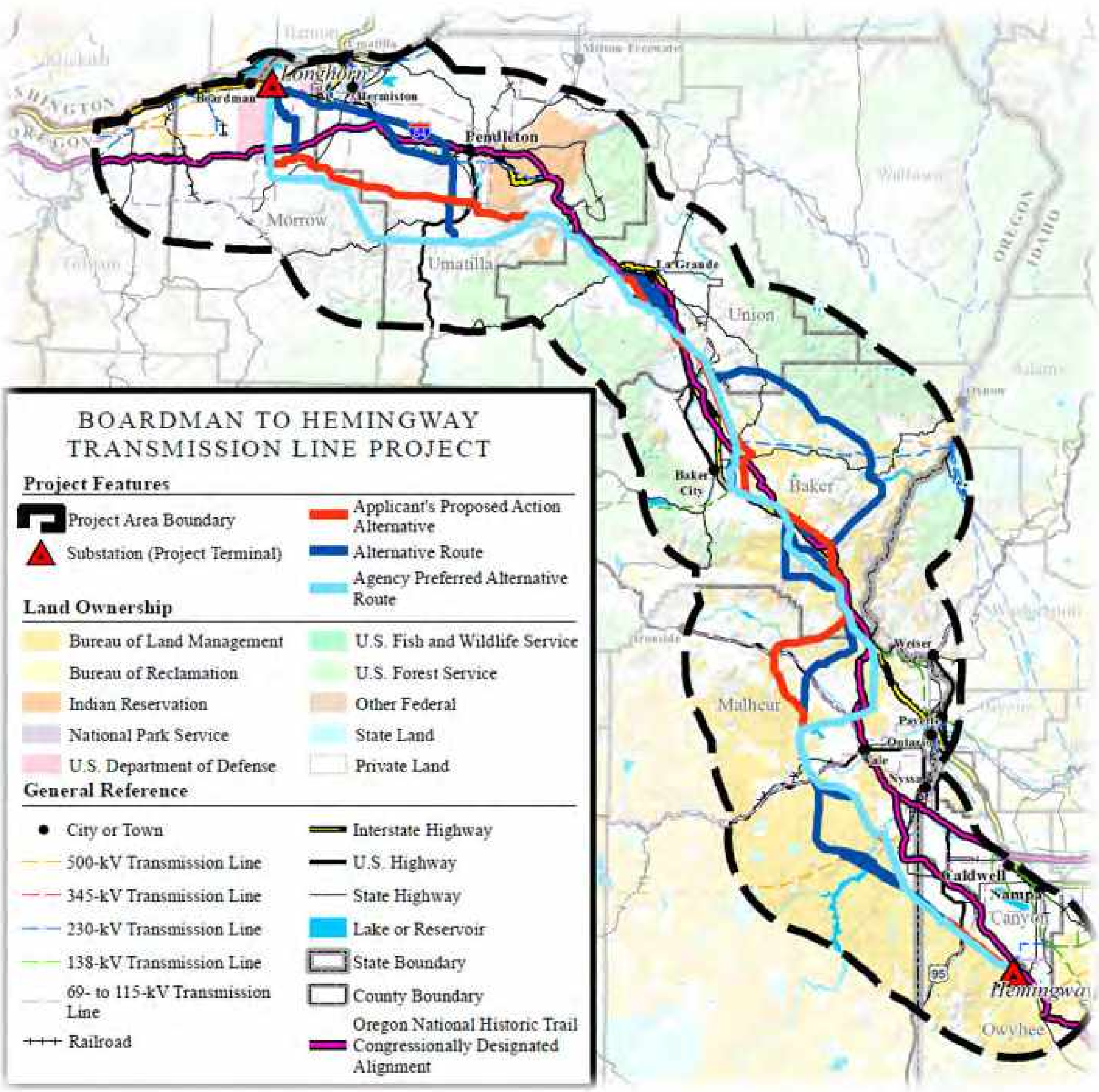

Figure 5. BLM final EIS routes

The conclusion of the BLM-led NEPA process, the BLM's ROD, resulted in a singular route—the BLM's Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the U.S. Forest Service [USFS], the Bureau of Reclamation, and the U.S. Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure 6 shows the BLM's Agency Preferred route.

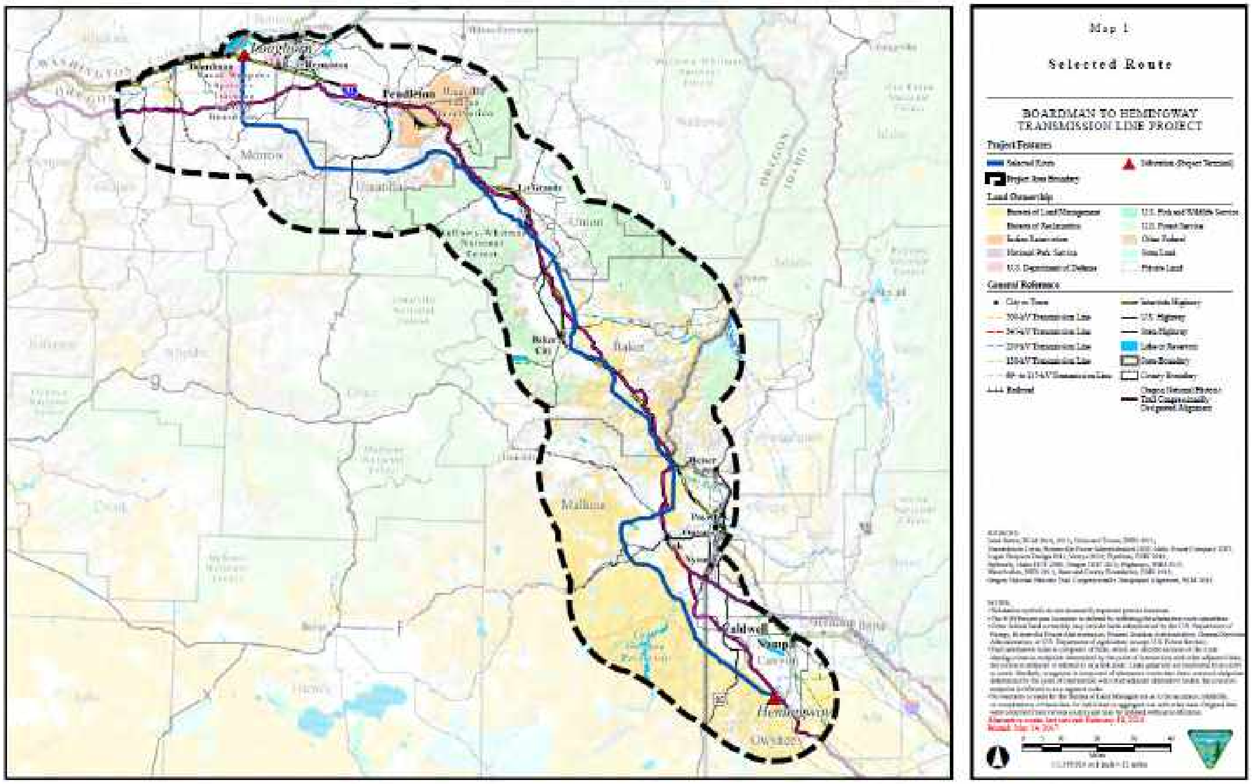

Figure 6. BLM Agency Preferred route from the 2017 BLM ROD

As discussed previously, the BLM-led NEPA process and the EFSC process are separate and distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM's Agency Preferred route, except for a small section of private property west of La Grande. The BLM's Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders in the area. The section the BLM chose was not the county's stated preference, nor was it the variation Idaho Power had worked with a large local landowner to modify to minimize impacts to his property.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the county's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power continues to work with the community to finalize which of the two variations in this area will be constructed. Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

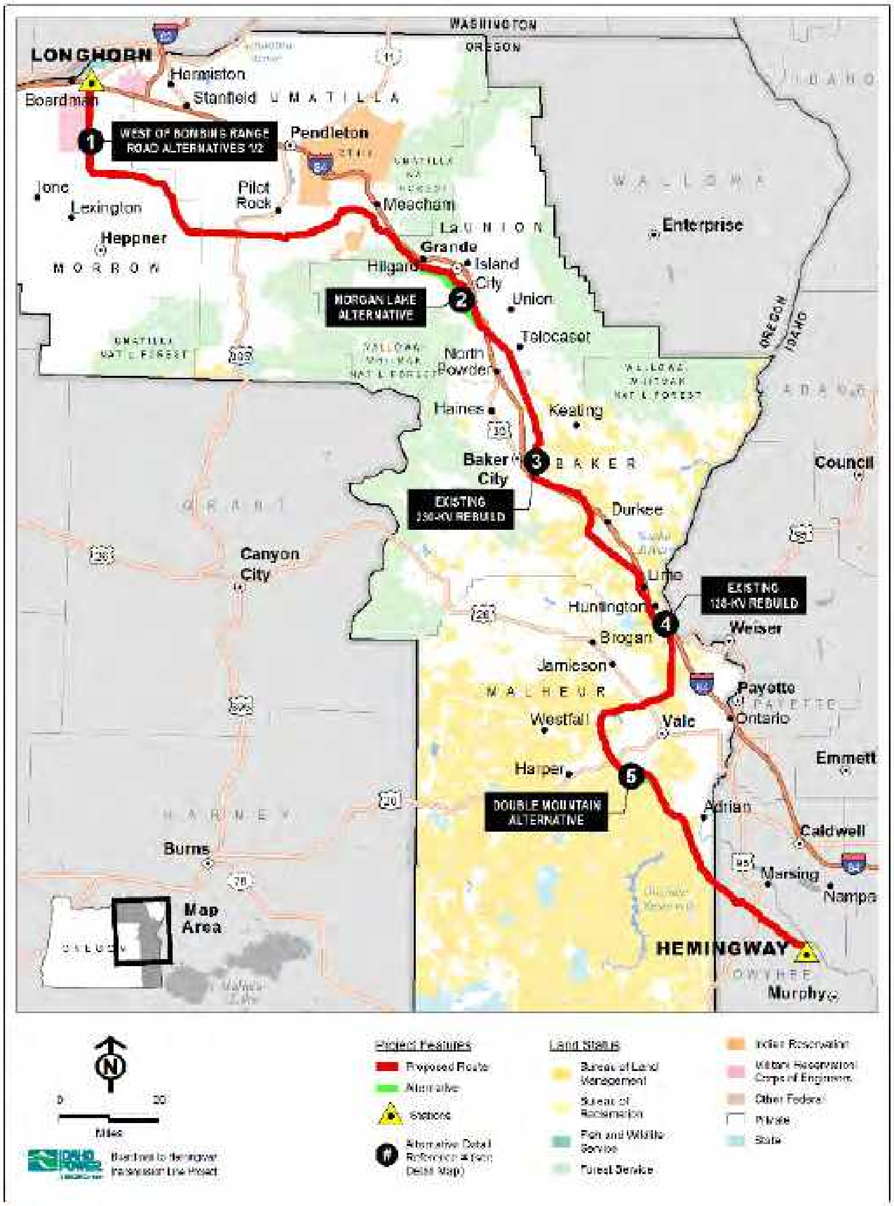

Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate

B2H Capacity Interest

Per the terms of the Joint Permit Funding Agreement, each coparticipant (funder) is assigned a permitting interest based on the annual weighted capacity expressed in the project. The permitting interest is determined by the sum of a funder's eastbound capacity interest and westbound capacity interest, divided by the total of all eastbound and westbound capacity interest. Table 5 details the capacity interest of each funder.

Table 5. B2H joint permit funding capacity interests by funder

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
Idaho Power	350 MW (Average) 500 MW (Summer) 200 MW (Winter)	0 MW	21.2%
PacifiCorp	300 MW	600 MW	54.5%
BPA	400 MW (Average) 250 MW (Summer) 550 MW (Winter)	0 MW	24.2%
Unallocated	0 MW	400 MW	

Idaho Power's capacity interest is seasonally shaped, with 500 MW of eastbound capacity from April through September and 200 MW of eastbound capacity from January through March and October through December. BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity from April through September and 550 MW of eastbound capacity from January through March and October through December. PacifiCorp's capacity is constant throughout the year. The sum of the capacity interest in the east-to-west direction is less than the rating (1,000 MW), so the unallocated capacity is divided among the funders based on their respective percentage permitting interest.

The seasonal capacity shaping is a great benefit for Idaho Power's customers, and one of the reasons why the B2H project is such a competitive and cost-effective option in the IRP process. Idaho Power is effectively purchasing 500 MW of capacity (peak summer need) at a cost based on 350 MW of capacity.

Capacity Rating—WECC Rating Process

Idaho Power coordinated with other utilities in the Western Interconnection via a peer-reviewed process known as the WECC Path Rating Process. Through the WECC Path Rating Process, Idaho Power worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation on the bulk power system. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

B2H Design

B2H is routed and designed to withstand catastrophic events, including, but not limited to, the following:

- Lightning
- Earthquake
- Fire
- Wind/tornado
- Ice
- Landslide
- Flood
- Direct physical attack

The following sections provide more information about the design of the B2H transmission line and address each of the catastrophic events listed above.

Transmission Line Design

The details below are not inclusive of every design aspect of the transmission line but provide a brief overview of the design criteria. The B2H project will be designed and constructed to meet or exceed all required safety and reliability criteria.

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lighting from striking conductors. See Figure 8 for a cross-section of a transmission line.

For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its conductive properties, and it provides the ability to move more power using a smaller amount of material.

Shield wires, typically either steel or aluminum, and occasionally including fiber optic cables inside for communication between substation equipment, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures, which provide an economical means to support large conductors for long spans over long distances. The typical structure height for B2H is 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,200 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (less structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

Foundations are the support mechanism that bind the structures to the earth and safely keep the phase conductors and shield wires in the air. For the B2H project, the foundations at each lattice tower structure are planned to be concrete-drilled pier shafts. A cylindrical hole will be drilled at each tower footing of adequate diameter and depth to support the loads applied to the structure from the shield wires and phase conductors. The loads applied to structures via shield wires and conductors are discussed in further detail below.

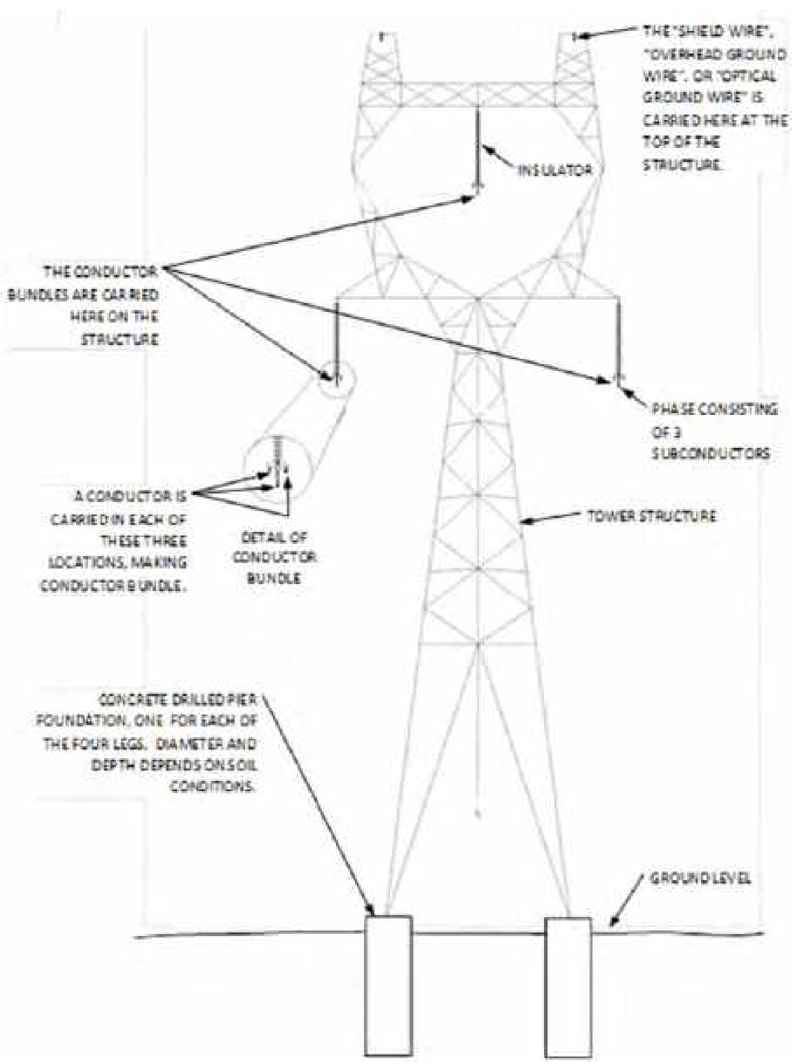

Figure 8. Transmission tower components

Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's EFSC application includes an exhaustive list of standards. Several notable standards are as follows:

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*
- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the provisions in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

Transmission Line Foundation Design

The 500-kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be concrete pier foundations designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake motion; historically, transmission structures have performed well under earthquake events,[10, 11] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[12] This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these

[10] Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192 © ASCE 2013.

[11] Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

[12] USDA RUS Bulletin 1751-801.

forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. When compared to other resource alternatives, B2H may be more resilient to smoke. For instance, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

Wind Gusts/Tornados

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

Ice

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

Landslide

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section above. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

Flood

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

Direct Physical Attack

A direct physical attack on the B2H transmission line will remove the line’s ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H’s ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

B2H Design Conclusions

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

PROJECT COPARTICIPANTS

PacifiCorp and BPA Needs

PacifiCorp and BPA are coparticipants in the permitting of the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H project indicates the regional significance of the project and the value the project brings to customers throughout the West. ~~Idaho Power, PacifiCorp, and BPA have worked closely to assign the capacity rights of the project to correlate with each party's needs.~~ More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

PacifiCorp

PacifiCorp is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp is a leading western US energy services provider and the largest single owner of transmission in the West, serving 1.9 million retail customers in six western states. PacifiCorp is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit pacificorp.com for more information.

The existing transmission path between the Pacific Northwest and Intermountain West regions is fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its share of the bidirectional capacity of B2H to increase reliability and to enable more efficient use of existing and future resources for its customers. PacifiCorp has identified the following list of additional benefits:

- **Customers:** PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.

- **Renewables:** PacifiCorp has identified B2H as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states.

- **Regional Benefit:** PacifiCorp, as a member of the regional planning entity NTTG~~,~~, (now NorthernGrid as of early 2020), supports the inclusion of B2H in the NTTG regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs.

- **Balancing Area Operating Efficiencies:** PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

- **Regional Resource Adequacy:** PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.

- **Grid Reliability and Resiliency:** The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.

- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation:** New legislation and rules for recently passed legislation are being developed to meet state specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.

- **EIM:** PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.

BPA

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately ~~28~~27 percent of the electric power used in the Pacific Northwest~~, which has an estimated population of over 13 million people~~. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

~~Similar to the Idaho Power IRP process for identifying cost-effective service alternatives,~~ BPA identified the B2H project plus associated asset exchange as ~~its top~~a priority for pursuit for ~~serving~~delivering power to serve the load of its customers in southeast Idaho. BPA's load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA's winter peak load couples well with Idaho Power's summer peak load ~~to allow~~allowing for seasonal shaping of the allocation of B2H capacity~~. Seasonal shaping of capacity would allow BPA to own 550 MW of B2H capacity in the winter and 250 MW of capacity in the summer, dramatically increasing~~, which increases the cost-effectiveness of the project~~ for BPA customers. A recent analysis performed by BPA continues to support the B2H project plus the asset exchange as its top priority for pursuit~~. For more information about the southeast Idaho load service analysis, visit bpa.gov.[13]

As a federal agency, BPA has responsibilities to comply with NEPA and ~~consider the environmental impacts of its actions~~other legal requirements prior to making a final decision or taking any final agency action, such as participating in transmission line construction~~. To that end, BPA was a cooperating agency in the development of the B2H EIS and continues to coordinate with the BLM and other federal agencies. BPA will ensure an appropriate environmental review has been conducted on any BPA-proposed action~~ or committing to enter into contracts associated with the B2H project~~ and plans to prepare a ROD to the B2H EIS~~. To that end, BPA will conduct any necessary reviews following completion of the ongoing coparticipant negotiations as appropriate~~ and in accordance with the B2H project's permitting schedule~~.

Coparticipant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012~~, with the intent to be joint owners of the B2H line.~~.
The agreement was amended on February 13, 2018. The Amended and Restated Boardman to

[13] Southeast Idaho Load Service analysis: bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

Hemingway Transmission Project Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands.

Related to the project, but not specific to the B2H permitting activities, the B2H coparticipants entered into an MOU on January 12, 2012, to accomplish the following: 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the coparticipants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project.

The funders are currently engaged in negotiations regarding potential agreements for the construction and ownership of the project.

Coparticipant Expenses Paid to Date

Approximately $~~104~~110 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through ~~September~~June 30, ~~2019~~2020. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $~~71~~74 million of that amount as reimbursement from the project coparticipants as of ~~September~~June 30, ~~2019~~2020. Coparticipants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

COST

Cost Estimate

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unanticipated expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million. Notable items that increased the cost relative to the 2017 IRP cost estimate include: increased steel and aluminum estimates, increased labor cost estimates, increased Longhorn substation estimate, and increased AFUDC.

Transmission Line Estimate

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500-kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

Substation Estimates

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation~~, but the station has yet~~ and must complete all NEPA reviews and other legal requirements before making a final decision to ~~be constructed~~construct Longhorn Substation. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

Calibration of Cost Estimates

The B2H estimate was reviewed and approved by BPA and PacifiCorp. BPA and PacifiCorp both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500-kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500-kV line (39 miles, in-service 2016)
- PacifiCorp: Sigurd to Red Butte 345-kV line (160 miles, in-service 2015)
- PacifiCorp: Mona to Oquirrh 500-kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

Costs Incurred to Date

Approximately $~~104~~110 million, including AFUDC, has been expended on the B2H project through ~~March 31, 2019.~~June 30, 2020. The $~~104~~110 million incurred through ~~September~~June 30, ~~2019~~2020, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses.

Transmission Revenue

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. However, historically, additional transmission wheeling revenue has not been quantified for transmission capacity additions. ~~For~~Starting with the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. ~~In the IRP filed in June 2019, to be extremely conservative, Idaho Power considered but did not include additional transmission revenues in its modeling. However, in Idaho Power's amended 2019 IRP filing, Idaho Power again chose to include the transmission revenue because it is reflective of the true cost to retail customers.~~ After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native-load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system.

Idaho Power's FERC transmission rate is calculated as follows:

$$Transmission\ Rate = \frac{Transmission\ Costs\ (\$)}{Transmission\ Usage\ (MW * year)}$$

Per the formula above, since transmission costs will likely go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission wheeling customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed a constant transmission usage by third parties (no increase or decrease) from 2018 levels.

~~Potential BPA and Idaho Power Asset Swap~~

~~Corresponding with the construction of B2H, Idaho Power and BPA are working to complete an asset swap that would allow Idaho Power to directly access the Mid-C market and avoid a BPA transmission wheeling charge. Such a swap would result in lower purchased-power prices for Idaho Power's customers. In return, BPA would be able to directly serve their load in southeastern Idaho and avoid an Idaho Power wheeling charge. As part of the 2019 IRP analysis, Idaho Power conservatively assumed there would be a wheeling charge to access Mid-C resources across B2H. If an asset swap were to take place, the cost of energy in B2H portfolios would be further reduced and make the B2H project an even more economic.~~

BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect, and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the Resource Need section.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power (2,050 MW total bi-directionally). Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

Clean Energy Future

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. Experts, in-depth studies, and even the American

Wind Energy Association, cite the need for an expanded and robust transmission system in a decarbonized future[14].

Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources)

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized transmission allowed them to build and share larger, more cost-effective and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 6 illustrates peak-load estimates, by utility and season, for 2028. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 68,000 MW. When all regions plan together, the total generating capacity can be reduced to 64,100 MW, a nearly 6 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

Table 6. 2028 peak load estimates—illustration of load diversity between western regions

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	8,400	10,600	10,600
British Columbia	9,700	13,100	13,100
Chelan	300	600	600
Grant	1,200	1,100	1,100
Idaho Power	4,400	3,500	4,400
Nevada	7,600	6,300	7,600
Northwestern Energy	2,000	1,900	2,000
PacifiCorp—East	10,400	8,900	10,400
PacifiCorp—West	3,800	4,000	4,000
Portland General	3,900	3,800	3,900
Puget Sound	3,800	5,300	5,300

[14] awea.org/Awea/media/Policy-and-Issues/Electricity/Transmission-Fact-Sheet.pdf
utilitydive.com/news/as-operators-update-grid-planning-for-renewables-transmission-remains-key/505065/
pv-magazine-usa.com/2019/08/30/clean-energy-groups-allies-call-for-overhaul-of-the-transmission-grid/

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Seattle City	1,300	1,600	1,600
Tacoma	600	1,000	1,000
Total	**59,600**	**64,100**	**68,000**

Note: From EEI Load Data used for the WECC 2028 ADS PCM

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than in the winter or even late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring/early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. In contrast, additional transmission capacity may enable utilities to leverage their transmission system to access generation capacity already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the *Second Amended 2019 IRP*, the portfolios that are the most cost-effective, other than B2H portfolios, include new natural gas generation. In this case, B2H provides an alternative to building carbon-emitting supply-side resources.

Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching higher cost, less efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction becomes constrained and power prices in Idaho and to the east will generally be high, while power prices in the Pacific Northwest will be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region.
The construction of B2H will help alleviate this constraint and create a win–win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a lower cost. The reverse situation is true as well—the Pacific Northwest will benefit from economical resources from the Mountain West region during certain times of the year.

Renewable Integration

To facilitate a transition from coal and fossil fuel resources to meet Idaho Power and surrounding state clean energy goals, the region requires new and upgraded transmission capacity to integrate and balance intermittent resources like wind and solar. Existing renewable generation is, at times, curtailed due to a lack of transmission capacity to move the energy to load. B2H can facilitate the transfer of geographically diverse renewable resources across the western grid and help ensure our clean energy grid of the future is robust and reliable.

Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500-kV transmission lines, such as B2H, substantially increase the grid's ability to recover from unexpected disturbances. Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500-kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.

2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect

Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

Resource Reliability

The forced outage rate of transmission lines has historically been a fraction of traditional generation resources. Availability and contribution to resource adequacy on the power grid, vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. Outage statistics between transmission and generation differ, as transmission varies in voltage class and total line length, while generators mostly differ in total size and fuel type. A telling sign of the reliability of a generation resource is the equivalent forced outage rate when needed (under demand) (EFORd). The EFORd is calculated based on the amount of time a generator is either de-rated, or completely forced out of service, while needed. De-rating a generator would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an unexpected forced outage rate of 0.4 percent (line miles/100 miles x SCOF x MTTR). Stated differently, the B2H transmission line is expected to have 99.6 percent availability when needed.

Table 7. NERC—AC transmission circuit sustained outage metrics

Voltage Class	Circuit Miles	No. of Circuits	No. of Outages	Total Outage Time (hr)	Frequency (SCOF) (per 100 circuit miles per yr)	Frequency (SOF) (per circuit per yr)	MTTR or Mean Outage Duration (hr)
200–299 kV	103,558	4,477.5	876	14,789.6	0.8459	0.1956	16.9
300–399 kV	56,791	1,623.6	394	19,766.8	0.6938	0.2427	50.2
400–599 kV	32,184	594.7	141	3,957.9	0.4381	0.2371	28.1
600–799 kV	9,451	110.0	28	342.4	0.2963	0.2545	12.2
All Voltages	201,985	6,805.8	1,439	38,856.7	0.7124	0.2114	27.0

By comparison, Table 8, lists the average EFORd for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFORd for gas power plants.

Table 8. NERC forced-outage rate information for a fossil or gas power plant

Generation Type	Unit Size	EFORd
Fossil (general)	All Sizes	7.96%
Fossil (general)	100–199 MW	7.49%
Fossil (general)	200–299 MW	5.85%
Gas	All Sizes	9.61%
Gas	1–99 MW	9.72%
Gas	100–199 MW	6.85%

A transmission line with a forced outage rate of less than 1 percent is significantly more reliable than a power plant, which has an EFORd of 7 to 10 percent. Of course, a transmission line requires generating resources to provide energy to the line to serve load. However, energy sold as "Firm" must be backed up and delivered even if a source generator fails. Therefore, Firm energy purchases would have an EFORd consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$Electrical\ Losses = Current^2 \times Resistance$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

Flexibility

Advances in technology are pushing certain existing generation resources toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the West, and for Pacific Northwest utilities to purchase energy from southern and eastern markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits, and the expansion of this transmission system (i.e., B2H) facilitates the realization of these benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. Additional Northwest utilities are joining the EIM increasing the value the transmission system provides. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that EIM participation does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

B2H Complements All Resource Types

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[15] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent[16]. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise installation would generate over 25 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

B2H Benefits to Oregon

Economic and Tax Benefits

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit ~~for the non-BPA owned portion~~ of the line is shown in Table 9 below~~.~~ ~~BPA, as a federal entity, does not pay taxes, so~~, excluding BPA's ~~25~~24 percent project interest ~~is excluded from the estimates~~. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

Table 9. Projected annual B2H tax expenditures by county*

Oregon County	Property Tax (excluding BPA's ~~25% ownership~~potential 24% interest)
Morrow	$~~270,295~~386,498
Umatilla	$~~569,656~~251,957
Union	$~~629,410~~947,594
Baker	$1,~~778,282~~868,433
Malheur	$~~893,567~~1,879,992
Total Oregon Tax Benefit	**$~~4,141,210~~5,334,474**

***The property tax valuation process for utilities is determined differently than locally assessed commercial and residential property. The Oregon Department of Revenue determines the property tax value for Idaho Power Company's ("Idaho Power" or "Company")

[15] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is nearly 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, Annual Technology Baseline: Electricity: 2019).

[16] NREL, System Advisory Model

property (transmission, distribution, production, etc.) as one lump sum value (i.e., not by individual assets~~).~~). The Oregon Department of Revenue then apportions and remits Idaho Power's lump sum assessed value to each county. It is from those values that the county generates property tax bills for the Company. Idaho Power converts its Oregon property tax payment by county into an internal rate that can be applied to Idaho Power's transmission, distribution, and production book investment to estimate taxes. This internally calculated tax rate is what was applied to the Boardman to Hemingway ("B2H") estimated book investment (project cost) to estimate property taxes. The table above summarizes the tax value derivation. For estimation purposes, the estimated property taxes are assumed at Idaho Power tax rates. PacifiCorp property taxes may differ from Idaho Power's property taxes. It is Idaho Power's understanding that BPA, as a federal agency, ~~is~~would not be obligated to pay taxes on its potential ownership interest. Therefore, the total estimated tax amount is discounted by BPA's ~~25~~24 percent potential ownership interest.

Local Area Electrical Benefits

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully used for existing customer commitments. Idaho Power currently serves customers in Owyhee County, Idaho, and Malheur County and portions of Baker County in Oregon. PacifiCorp, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's network transmission rate to receive ~~power and~~ transmission service from the BPA system. ~~If~~ While BPA ~~finds less expensive solutions~~continues to ~~meet service obligations to customers in southeast Idaho and Wyoming, costs are kept low for other BPA customers, including OTEC, UEC, and CBEC. In other words, BPA customers in Oregon benefit by finding a low-cost solution for customers in Idaho and Wyoming. BPA's~~refine its financial analysis~~ to date has projected~~, its initial modeling indicates that a share of the B2H project with asset exchange ~~appears the most~~may be a cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and, as discussed previously, B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230-kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

Risk

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the *Second Amended 2019 IRP*, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power' resource needs.

Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power's share of the B2H project is $292 million, including Idaho Power's AFUDC. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

The B2H project has considerable capital-cost bandwidth. Idaho Power notes that the B2H capital cost includes a 20 percent cost contingency, which is not included for other resource options considered. Based on net present value (NPV) analysis over the 20-year planning horizon, Idaho Power's cost share of the B2H project could ~~almost double~~increase substantially beyond the 20 percent cost contingency, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, ~~non-~~B2H-alternative portfolio under planning ~~assumptions~~conditions. This cost difference is illustrated in the *Second Amended 2019 IRP* Table 9.7. The best B2H Portfolio is PGPC B2H (1), and the best B2H-alternative Portfolio is PGPC (2). Under planning conditions, the NPV difference in cost between these portfolios is about $35 million. This $35 million, compared to the total $108 million NPV of Idaho Power's share of the B2H project, including the 20 percent cost contingency, represents a large gap and illustrates a low capital-cost risk.

Market Price Risk

Idaho Power performed two separate risk analyses on the 24 resource portfolios developed by the AURORA model for the *Second Amended 2019 IRP*. Under the first risk analysis, total portfolio costs (i.e., total of fixed and variable costs) were modeled under three higher-priced natural gas and carbon cost scenarios. The second risk analysis was a stochastic risk analysis, where total portfolio costs were modeled for 20 iterations, or futures, on the following stochastic risk variables: natural gas price, customer load, and hydro condition. These analyses are described in Chapter 9 of the *Second Amended 2019 IRP*.

Idaho Power emphasizes that wholesale electric market prices are not specified inputs to the AURORA model, but rather are output by the model in response to various factors and are strongly driven by positive correlations with natural gas price and carbon cost, and a negative correlation with hydro condition. Thus, the risk analyses performed by Idaho Power are considered to study the relative exposure of the IRP resource portfolios to the studied inputs (e.g., natural gas price), and by extension to wholesale electric market prices output by the AURORA model.

The risk analyses performed for the *Second Amended 2019 IRP* indicate that total portfolio costs, specifically variable costs associated with the operation of portfolio resources (e.g., cost of imported wholesale electric energy), are markedly affected by the studied risk variables. For example, the total portfolio costs for Portfolio ~~16-4 ranged from $5.997~~PGPC B2H (1) had a $3 billion ~~under~~range between planning case conditions for natural gas price and carbon cost ~~to $9.153 billion under~~and high case conditions for both inputs (Table 9.~~9~~7 of the *Second Amended 2019 IRP*). Similarly, Portfolio ~~16-4~~PGPC B2H (1) costs ranged by about $2 billion across the 20 stochastic iterations ~~from $5.63 billion to $7.35 billion~~ (Figure 9.6 of the *Second Amended 2019 IRP*). Thus, the risk analyses indicate that the studied risk variables strongly influence portfolio costs. However, the analyses also importantly suggest that the relative exposure to the studied risk variables, including by extension wholesale electric market prices, does not dramatically favor one portfolio over another; Portfolio ~~16-4~~PGPC B2H (1) and other B2H-based portfolios exhibit similar ranges in their portfolio costs across the risk scenarios as B2H-alternative portfolios.

Liquidity and Market Sufficiency Risk

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak. Idaho Power's peak occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

Data Point 1. Peak Load Analysis from Table 6

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest[17] have forecast 2028 winter peaks that exceed their forecast 2028 summer peaks by a combined 8,300 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2023—Northwest Power Conservation Council Report

Idaho Power's review of recent assessments of regional resource adequacy in the Pacific Northwest included the *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the Northwest Power and Conservation Council (NWPCC) Resource Adequacy Advisory Committee (RAAC). 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,[18] 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 megawatts 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). 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.

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[17] Load serving entities from Table 6 included in stated figure are Avista, BPA, British Columbia, Chelan, Grant, PacifiCorp—West, Portland General, Puget Sound, Seattle City, and Tacoma.

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

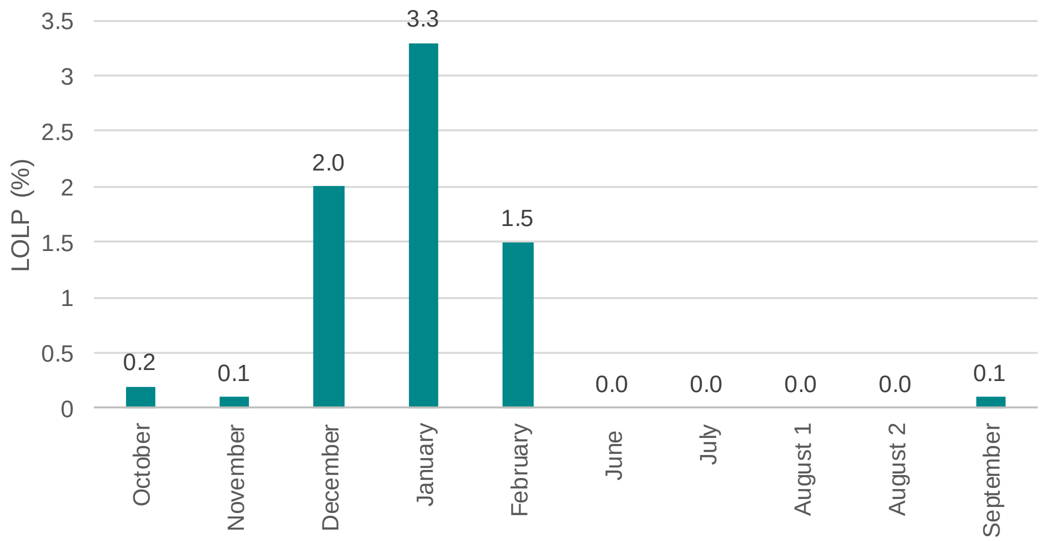

Figure 9. LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

Data Point 3: 2018 Pacific Northwest Loads and Resources Study—BPA

Idaho Power's review of recent regional resource adequacy assessments also included the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[19] Idaho Power concludes from this analysis that: 1) summer capacity will be available in the future, and 2) additional summer capacity will likely be added as the region adds resources to meet winter peak demand. BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled 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:

[19] 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

Table 10 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

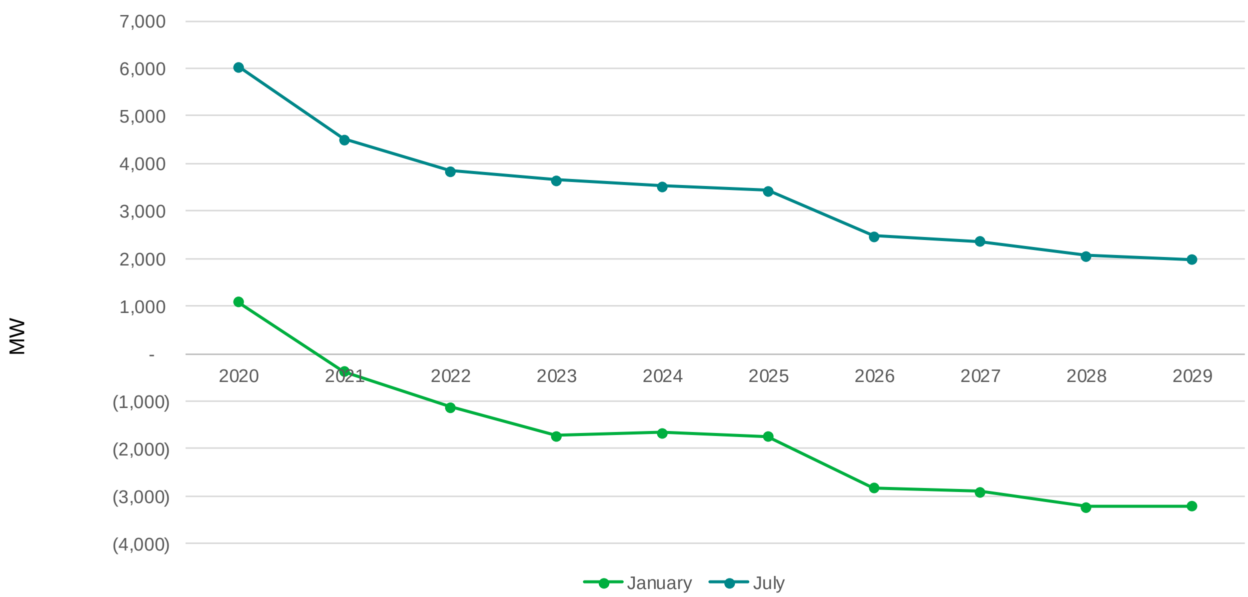

Figure 10. BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Data Point 4: FERC Form 714 Load Data

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 11.

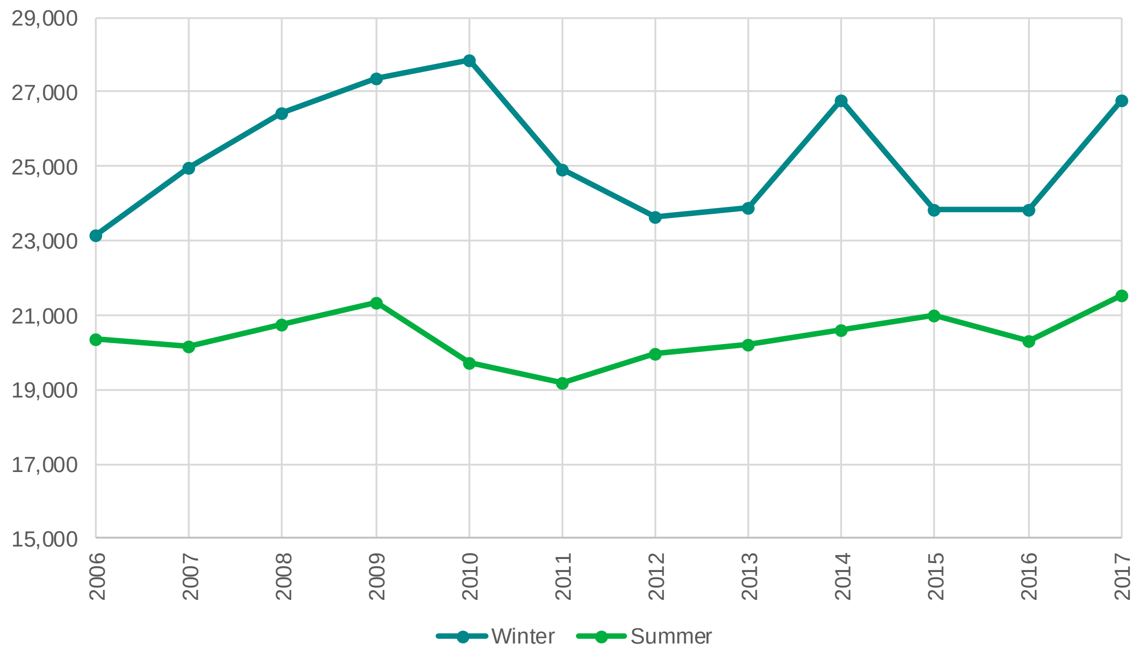

Figure 11. Peak coincident load data for most major Washington and Oregon utilities

Figure 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 (winter peaking), 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 (more water in summer compared to winter).

Data Point 5: Northwest and California Renewable Portfolio Standards

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in more solar generation throughout the region and may also result in the addition of dispatchable flexible ramping resources, such as the Port Westward 2 power plant installed by Portland General Electric in 2014.

Market Sufficiency and Liquidity Conclusions

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, risk analyses conducted in the *Second Amended 2019 IRP* indicates B2H remains cost competitive over a wide range of risk scenarios, including variations in market prices because of variations in input variables.

Coparticipant Risks

Idaho Power, BPA, and PacifiCorp, collectively referred to as coparticipants or funders, are fully engaged in permitting activities. and have had ongoing construction and operating agreement discussions.

Under the terms of the Joint Permitting Agreement, the funders may withdraw from the agreement at any time and for no reason. In such an event, the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

In the event that either BPA or PacifiCorp were to decide not to move forward with the project, Idaho Power believes other parties may have interest in potential ownership in B2H. At least one additional party was involved in the original negotiations that ultimately ~~lead~~led to the current three-party 2012 Joint ~~Funding~~Permitting Agreement. Additionally, Idaho Power has had discussions with other entities that may have interest in the B2H project. ~~Even if all three of the current funders remain committed to the project~~In fact, it is entirely possible that additional partners may commit to the project – even assuming BPA and PacifiCorp remain committed. Any consideration of additional project coparticipants would be discussed and agreed on by the current funders.

As noted in the *Second Amended 2019 IRP* Boardman to Hemingway Participant Update of Chapter 1, 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.

Nevertheless, changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk by authorizing the project on 85.6 miles of BLM-administered land. The U.S. Forest Service also issued a ROD authorizing the project on 8.6 miles of National Forest land in 2018, and the U.S. Navy issued a ROD in 2019 authorizing the project on 7.1 miles of Navy land. The Oregon site certificate process is the next major step in siting~~, and~~; in ~~2019~~2020, ODOE issued ~~a Draft~~the Proposed Order recommending approval of the project. While the ~~recommendations in the Draft~~ Proposed Order are subject to ~~review and change by EFSC, reaching~~a Contested Case proceeding, the ~~Draft~~ Proposed Order ~~stage itself~~ is a major milestone in the state permitting process and the recommendations are certainly encouraging. Idaho Power believes that the significant progress in both federal and state permitting processes minimizes future siting risk.

Schedule Risk

As of the date of this appendix, Idaho ~~Power has schedule scenarios for~~Power's scheduled B2H in-service ~~dates in~~date is 2026 or later. At a high level, remaining activities prior to energization are: permitting, coparticipant agreements, preliminary construction, material procurement, and construction.

As noted above, the permitting phase of the project is ongoing. For federal permitting, the B2H project ~~recently~~ achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017 and subsequent Right-of-Way Grant in January 2018. The ROD and ROW Grant formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The U.S. Forest Service ROD was issued in November 2018 and a right-of-way easement was issued in May 2019. A Navy ROD was issued in September 2019 and a Navy easement ~~is expected in early 2020.~~was issued in May 2020. The project is on track to receive the federal notice to proceed in late 2022 or early 2023.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the Amended Application for Site Certificate to the ODOE and an application completeness determination from ODOE in fall 2018. The ODOE also issued a Draft Proposed Order in May 2019. A Proposed Order ~~is expected~~was issued in ~~early~~July 2020, and a Final Order and Site Certificate are expected in 2021. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the ~~ODOE~~EFSC does not issue a Site Certificate in 2021.

With the receipt of the BLM ROD and ROW easement, and a ~~Draft~~ Proposed Order from ODOE, sufficient route certainty exists to continue with preliminary construction tasks. In 2019, Idaho Power began the process of acquiring necessary federal authorizations to conduct geotechnical explorations. At the time of writing, Idaho Power is in the process of ~~developing a detailed design (i.e., preliminary construction) bid package. In 2020, Idaho Power plans to initiate~~initiating the following activities for 2021: detailed design, ROW option acquisition, ~~LIDAR (aerial mapping),~~ legal surveys, and geotechnical investigation. ~~The~~LIDAR (aerial mapping) has been recently completed for the entire B2H ~~co-participants have not formally decided on the construction contracting method for the project, so the preliminary construction~~route and ~~construction schedule~~any proposed alternatives. Construction activities ~~remain preliminary until contracts~~ are expected to commence in ~~place. Currently, Idaho Power believes a 2026~~2023 with the expected project in-service date ~~is achievable~~in 2026.

Catastrophic Event Risk

As detailed in B2H Design section of this appendix, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity and an additional path to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system. Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

PROJECT ACTIVITIES

Schedule Update

Permitting

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017 and the ROW Grant on January 9, 2018. These actions formalized the conclusion of the siting process and federally required NEPA process. The BLM ROD and ROW Grant provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. With the issuance of the U.S. Forest Service ROD and easement, and the issuance of the U.S. Navy ROD, all major federal decision records have been achieved~~.~~.

For the State of Oregon permitting process, Idaho Power submitted the Amended Application for Site Certificate to the ODOE in summer 2017 and ODOE issued a Draft Proposed Order in May 2019~~.~~ and a Proposed Order ~~is expected~~ in ~~early~~July 2020~~ and~~. A Final Order and Site Certificate is expected in 2021.

The NEPA and EFSC processes are separate and distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a “desktop” level. Information is brought into the process on a phased-approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analyses to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy, coming in at over 20,000 pages.

Post-Permitting

To achieve an in-service date in 2026, preliminary construction activities must commence parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys (light detection and ranging (LiDAR) aerial mapping

- Sectional surveys
- ROW acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction. The material acquisition and construction activities are expected to take approximately 3 ~~to 4~~ years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project coparticipants.

CONCLUSIONS

This B2H *Second Amended* *2019 IRP* appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the *Second Amended* *2019 IRP*, B2H was identified as the least-cost and least-risk resource to serve future capacity and energy future needs. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is nearly 60 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[20] In addition to the B2H capacity benefits, B2H is expected to have the lowest levelized cost of energy—lower than the expected costs for a combined-cycle gas plant and utility-scale solar.[21]

The B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. Pursuant to EFSC's least-cost plan rule, the need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[22] ~~In this case,~~The OPUC has already acknowledged the construction of B2H in Idaho Power's 2017 IRP. Idaho Power ~~seeks to satisfy EFSC's least-cost plan rule's requirement through an~~asks the OPUC to confirm its acknowledgement of ~~it's~~B2H in the company's *Second Amended 2019 IRP*.

[20] Amended 2019 IRP Figure 7.5.

[21] Amended 2019 IRP Figure 7.6

[22] OAR 345-023-0020(2).

Appendix D-1. Transmission line alternatives to the proposed B2H 500-kV transmission line

Table D-1

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

Scenario	Line Capacity[1]	Potential Path 14 West-East Increase[2]	Losses on New Circuit(s)[3]
a. Longhorn to Hemingway 230 kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230 kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345 kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500 kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500 kV—two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500 kV double circuit	6,428 MW	1,235 MW	2.9%
g. Longhorn to Hemingway 765 kV single circuit	4,770 MW	1,200 MW	2.4%

1 Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

2 Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

3 Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

Table D-2

Comparison of Transmission Line Capacity Scenarios—Rebuild Existing Lines to the Northwest

Scenario	Line Capacity[1]	Potential Path 14 Increase[2]	Losses on New Circuit(s)[3]	Length of Line/ New ROW[4]
h. Replace Oxbow-Lolo 230 kV with Hatwai—Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles/136 Miles
i. Replace Oxbow-Lolo 230 kV with Hatwai—Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles/167 Miles
j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap—Hemingway 500 kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles/150 Miles
k. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap—Hemingway 500 kV—No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles/181 Miles
l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway.	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles/168 Miles

1 Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

2 Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

3 Estimated Losses are percent losses for the new line at the Potential Rating west-east loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

4 In addition to utilizing existing 230 kV right-of-way ("ROW"), each of the scenarios above will require new ROW to be obtained.

Appendix D-2. Detailed list of notable project milestones

- June~~,~~ 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka "Bombing Range")
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of the Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – The BLM issues a Record of Decision (ROD) for the B2H project. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

- January 9, 2018 – BLM and Idaho Power sign the BLM ROW Grant for the B2H project.
- September 21, 2018 – ODOE determines the B2H Application for Site Certificate is complete.
- September 28, 2018 – Idaho Power files the Application for Site Certificate with ODOE.
- November 13, 2018 – The U.S. Forest Service issues a Record of Decision for the B2H project
- May 22, 2019 – The Oregon Department of Energy issues a Draft Proposed Order.
- May 28, 2019 – The U.S. Forest Service and Idaho Power sign a ROW easement agreement for the B2H project.
- May 29, 2019 – Bonneville Power Administration issues a Record of Decision for moving an existing 69 kV line from the U.S. Navy bombing range to accommodate the B2H project.
- September 2019 – U.S. Navy issues a Record of Decision for 7.1 miles of project on U.S. Navy Naval Weapons Training Facility Boardman, Oregon.
- March 23, 2020 – U.S. Navy and Idaho Power sign a ROW easement for the B2H project.
- July 2, 2020 – ODOE issues the Proposed Order and notification of the Contested Case.
- September 25, 2020 – Oregon DOJ holds Contested Cast pre-hearing conference.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 74

IDAHO POWER COMPANY

Attachment 3

2019 Integrated Resource Plan Review Report

October 2, 2020

IDAHO POWER.
An IDACORP Company

INTEGRATED RESOURCE PLAN
REVIEW REPORT

2019

OCTOBER • 2020

BALANCING OUR ENERGY NEEDS • TODAY AND TOMORROW

SAFE HARBOR STATEMENT

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1. Introduction and Background

The *2019 Integrated Resource Plan Review Report* (*IRP Review Report*) is the culmination of six weeks of comprehensive study of Idaho Power's resource planning practices and modeling associated with the 2019 IRP cycle. In the sections below, Idaho Power details the four-step review process undertaken to deconstruct and examine the foundational elements of the IRP analysis—including model inputs and assumptions, data import, model system settings, model verification and validation, and model outputs—and the actions taken to resolve identified issues. The document, however, stops short of delving into the company's actual IRP analysis and findings. As such, this report should be treated as a prologue to Idaho Power's ultimate Integrated Resource Plan in the 2019 cycle, the *Second Amended 2019 IRP*.

Idaho Power embarked on this review following the discovery of issues that required further analysis. As a result, the 2019 cycle has been more circuitous than a typical IRP cycle, largely due to the introduction of modeling tools that Idaho Power was using for the first time. The history of the 2019 IRP is detailed below and offers important context around the events that led to the IRP review:

- On June 28, 2019, Idaho Power Company filed its original *2019 IRP* with the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC). At the recommendation of Idaho Power's Integrated Resource Plan Advisory Council (IRPAC), the company for the first time used a Capacity Expansion Modeling (CEM) approach to build and optimize alternative portfolios for the IRP. Specifically, the company employed the Long-Term Capacity Expansion (LTCE) tool in AURORA, which allows for portfolios to dynamically adjust based on the impacts of new capacity additions and other factors.

- Subsequent to the initial filing, Idaho Power discovered that the LTCE model optimized portfolios for the entire Western Electricity Coordinating Council (WECC) region, but not necessarily for Idaho Power's system in particular. For this reason, on July 19, 2019, the company notified the Commissions of the need to perform supplemental analysis to ensure that the IRP yielded a least-cost, least-risk solution specific to IPC's service area, and asked that the Commissions refrain from adopting a procedural schedule until an amended IRP could be filed.

- On January 31, 2020, Idaho Power filed its *Amended 2019 IRP* and identified eight modifications to the original IRP, including implementation of a new manual modeling step to ensure that the LTCE results yielded the best possible economic and reliability outcomes for Idaho Power's system and its customers. Importantly, these changes resulted in only two modifications to the company's near-term Action Plan associated with the IRP Preferred Portfolio: 1) The removal of the Franklin Solar facility, and 2) The addition of 5 megawatts (MW) of demand response was moved from 2026 to 2031.

- On May 29, 2020, the company provided a correction to the IRP related to the costs associated with the Jim Bridger Power Plant (Bridger). The need for this correction was identified while preparing a response to a discovery request in a separate docket before the IPUC. Upon review, it was discovered that certain Bridger-related costs had inadvertently been excluded from portfolios in which a Bridger unit was exited prior to the existing shutdown date of 2034. This correction required the replacement of seven pages in the company's *Amended 2019 IRP* but did not impact the company's recommendation of the Preferred Portfolio.

- In June 2020, the company identified an issue in the *Amended 2019 IRP* related to the modeling cost treatment of its coal plants at which point the company asked the IPUC and the OPUC for additional time to conduct a comprehensive review of the IRP modeling process to ensure the accuracy of the 2019 IRP.
- The company filed a motion to suspend the 2019 IRP with both Commissions on July 1, 2020. Later that month, on July 31, 2020, the company provided an update on the review process and offered October 2, 2020, as the date to submit its final IRP, the *Second Amended 2019 IRP*, along with the full documentation of the review process in the form of this *2019 IRP Review Report*.

In the sections below, Idaho Power details each step of the review process, the review outcomes, and actions taken to resolve identified issues with the IRP process. While the conditions were not ideal, Idaho Power is grateful for the opportunity to conduct such a thorough investigation of its approach and practices related to the IRP. The outcome of this review not only ensures the validity of the 2019 IRP, but also offers valuable lessons and insights that can be applied to future IRPs.

2. IRP Review – Objectives, Methodology, and Outcomes

Idaho Power conducted a comprehensive review to deconstruct and examine all aspects of the 2019 IRP analysis, from model inputs to model outputs. To accomplish this review, the company formed a team (IRP Review Team) of subject matter experts from its Planning, Engineering & Construction, Power Supply, 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 performed a four-step evaluation of the IRP process. Step I included identification of key IRP inputs, sources and input-related assumptions. Step II involved evaluating the manner in which key inputs were entered into the AURORA model. Step III involved a comprehensive review of the system settings applied within the AURORA model. Step IV included validation of the AURORA model outputs to ensure results were reasonable/expected with respect to each of the key inputs.

2.1 IRP Review Objectives

The company identified several objectives for the 2019 IRP review:

- Provide clarity around 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 way each step is performed
- Identify appropriate and efficient resolutions for any identified issues
- Ensure compliance with industry standards and regulations

This review process provides increased transparency into the complexities of IRP development. Lessons learned from this review were not only applied to the 2019 cycle but can be used in the development of future IRPs to ensure the process is more efficient, transparent, and accurate.

2.2 IRP Review Process and Methodology

As described above, the company performed a four-step evaluation of the IRP process. Detailed below are the specific actions taken within each step.

Step I - Input Data and Source Review

In order to conduct a full examination of the multitude of inputs used in the IRP process, 11 sub-teams were formed, each with appropriate subject matter experts, to examine individual categories of AURORA model input. The sub-teams included the following:

- Forecast inputs for natural gas (sub-team 1)
- Forecast inputs for the hydrologic system and stream flow conditions (sub-team 2)
- The company's load forecast (sub-team 3)
- Forecast inputs for coal costs as well as operating parameters and cost inputs related to the company's coal units (sub-team 4)
- Operating parameters and cost inputs related to the company's existing natural gas plants (sub-team 5)
- Inputs related to 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)
- Transmission system inputs related to the B2H project (sub-team 9)

- Financial inputs and future supply-side resources related to items such as the Weighted Average Cost of Capital, fixed and variable operations and maintenance (O&M) costs, property tax treatment, and modeled future supply-side resources (sub-team 10)
- Reliability inputs related to the company's regulating reserve requirements (sub-team 11)

The sub-teams reviewed all aspects of these inputs, including cross-verification against source materials, examination 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).

The process for validating each key input was unique and is described in Section 5 of this report. The company also used process mapping (or flowcharting) of key IRP inputs to provide insight into the complex IRP development via a visual representation. A flowchart for each key input shows how each input is treated and evaluated in the IRP process and also shows existing relationships between the input and other inputs and/or stages of the IRP process. These flowcharts are located at the end of each input sub-section in Section 3.

To complete Step I of the review process, the input sub-teams determined whether their specific input(s) had been treated appropriately or whether an adjustment was necessary. If the input was determined to be reasonable, the sub-team moved to Step II of the review. If the input required adjustment, the issue was documented, and a method of correction was identified and conducted to resolve the issue. Additionally, sensitivity analyses were performed to determine the magnitude of identified adjustments, individually and collectively (see Step IV of the review process for more detail).

Step II – Feeding Data into the Model

In Step II, 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 reviewed export files of input data within the AURORA model and reconciled it to information gathered in Step I. This reconciliation of the input data contained within the AURORA model to the source files ensured that any conversions and transformations were conducted properly, and that data fed into AURORA were accurate and consistent with the information provided by each sub-team.

Step III – Model Settings and Processing

In Step III, the IRP Review Team analyzed how AURORA treats data within the model itself—referred to as modeling logic. For this step, the company's modeling experts assessed the 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. In addition, the Review Team consulted with Energy Exemplar, the developers of the AURORA model, for guidance on specific topics.

Step IV – Output Review

Finally, in Step IV, the IRP Review Team examined the AURORA model outputs to ensure the model was producing logical and consistent results. Within this step, if the sub-teams determined the output required further evaluation, additional work was performed to validate model operations as necessary. For identified adjustments from Steps I through III, sensitivity runs were completed to determine their ultimate impact on model outputs. These sensitivities compared the input data used in the *Amended 2019 IRP* and its associated results to the IRP Review Team's model run results from adjusted model inputs. The results of those sensitivity runs are discussed in Section 5.

2.3 IRP Review Outcomes

At the conclusion of the four-step review process, the company identified a range of appropriate adjustments to model inputs and treatment of data within the model. Some of these changes were identified by the company prior to commencement of the IRP review and some were discovered during the review. All identified changes, regardless of when they were first discovered, were fully evaluated in the review process. The following adjustments were identified during the review process:

Coal Plant Inputs and Cost Treatment

The following adjustments were identified in the review of coal plant inputs and cost treatment:

- Jim Bridger Plant
    - 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 requiring an update to both the fixed O&M and decommission hurdle rates.
    - 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.
    - 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.
    - The fixed cost rates for Bridger Unit 4 were inadvertently referencing the table of fixed costs for Bridger Unit 3 within AURORA.
    - Idaho Power's share of the variable O&M costs associated with the Bridger units should have been modeled as one third of the total projected costs.

- North Valmy Plant
    - 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.
    - The Valmy fixed O&M rate needed to be updated to adequately capture savings associated with a shutdown of Unit 2 prior to 2025.
- 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.

Natural Gas Inputs

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

- Natural Gas Transport Costs: Variable transport costs were inadvertently excluded in the model. This relatively small cost stream was reviewed for accuracy and added to the natural gas input costs.
- 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, startup costs were entered, resulting in a reduction in peaker dispatch and more accurately reflecting a logical and expected outcome.
- 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, 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:

- Property tax rates were outdated. Upon review, the rates were adjusted to reflect information available when the 2019 IRP analysis was originally performed.
- Annual insurance premium rates inadvertently reflected the wrong decimal place value. This issue was corrected during the review process.

Transmission Inputs

Two adjustments were identified in the review of transmission system inputs:

- The loss and/or wheeling rates applied to some transmission lines required adjustment. Rates were adjusted and now reflect correct information.
- The following adjustments to transmission capacity were identified in the review process and have been entered into AURORA:
  - Following exit from the Boardman coal plant, available transmission capacity was understated (53 MW).
  - The Idaho Power transmission export capacity on Boardman to Hemingway was understated (85 MW).
  - Idaho to Northwest west-to-east capacity in January through May and September through December post July 2026 was understated (200 MW).
  - The transmission capacity on Bridger West was adjusted to reflect Idaho Power's ownership share.

Reliability Inputs

The following adjustments were identified in the review process:

- The solar and wind allocation factors for downward regulation referenced the upward allocation factors (RegUp). These allocation factors are now referencing downward regulation (RegDn).
- 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.

The IRP Review Team, having identified the above issues, ran the adjustments through select resource portfolios to determine the impact to the overall IRP results—impact was defined as the degree of change from prior results in the *Amended 2019 IRP*. The model was run separately for each individual adjustment, as well as with the collective set of adjustments. The details of each adjustment, the results of the model runs, and the identified resolution of each adjustment is further described in Section 6 of this report.

3. MODEL INPUTS AND VERIFICATION

As described previously, a total of 11 sub-teams were formed, each with appropriate subject matter experts, to examine individual categories of AURORA model input data. In Step I of the review process, each of the sub-teams conducted deep-dive interviews with those at Idaho Power responsible for preparing the data for use in AURORA. Company subject-matter experts helped with the evaluation of a key input, its assumptions, and sources. In Step II of the review process, the sub-teams conducted interviews with members of the company's IRP planning team to analyze how each key input is fed into the AURORA model, and gain an understanding, if applicable, of any necessary changes or conversions that were made to the data inputs to make them model ready.

The following section details the review process performed in Steps I and II for each of the sub-teams. A flowchart (or process map) accompanies each key input.

3.1 Natural Gas Price Summary

3.1.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs related to the natural gas price forecasts, as well as the final and comprehensive natural gas price forecast, which combines the forecast natural gas prices and the associated forecast of fuel transportation costs. The following summarizes the inputs and key assumptions for natural gas:

Forecasted Gas Rate Sources

The company uses three natural gas price forecasts in the IRP:

1. Platts' Henry Hub natural gas price forecast
2. The U.S. Energy Information Administration's (EIA) Henry Hub low oil and gas forecast
3. EIA's Henry Hub reference mid gas price forecast.

Transportation Costs

In addition to the price forecast, the company adds transportation costs specific to bringing gas from a regional hub to Idaho Power's resources. Transportation cost components are as follows:

1. Flat transport cost – Tariff costs fluctuate from year to year and are difficult to predict into future years, so the current rate is assumed for the next 20 years.
2. Transport variable costs – These costs were also assumed at the current tariff rate since costs fluctuate from year to year and are difficult to predict into the future.
3. Transportation expansion costs based on existing available pipeline capacity and generation – It was determined that after roughly 600 MW of generation it would be

necessary to diversify natural gas supply to the Rocky Mountain supply region. Currently, gas is sourced exclusively from Canadian supply and the path from the Rockies to Idaho is fully subscribed, meaning a pipeline expansion would be necessary.

4. Monthly shaping of gas forecasts using Platt's five-year forecast.

For the 2019 IRP analysis, the company utilized three natural gas price forecasts, each prepared by a third-party entity (i.e., Platts and EIA). Because these inputs are prepared externally, it was determined that no further verification was necessary beyond ensuring that the values in the forecasts were appropriately and accurately reflected in the model input tables.

The company utilized data from the Northwest Pipeline tariff to derive the fixed and variable natural gas transport costs used in the 2019 IRP. As part of the review, the company's forecast of costs was reconciled to the Northwest Pipeline tariff.

Transportation expansion costs used in the 2019 IRP were provided by Northwest Pipeline. Idaho Power was provided with an estimate for an expansion of the pipeline from Northwest Pipeline's Rocky Mountain supply region to Idaho. The estimated pipeline expansion costs were then modeled to determine the cost for four natural gas resources: Combined-cycle combustion turbine (CCCT), single-cycle combustion turbine (SCCT), reciprocating engine with a nameplate of 111.1 MW, and reciprocating engine with a nameplate of 55.5 MW.

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, the Natural Gas Price Sub-Team identified no concerns with the natural gas price inputs to the 2019 IRP.

3.1.2. Transferring Inputs into AURORA

To ensure that the natural gas price data prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the natural gas price input data within the AURORA model and tied those inputs to the various source files prepared by the responsible Idaho Power business unit. During this process, it was determined that the natural gas price inputs prepared for the 2019 IRP reconciled to the natural gas price inputs within AURORA, with the exception of variable transport costs, which had not been loaded into AURORA. This adjustment was made, and a sensitivity analysis was performed. The results of the sensitivity analysis are provided in Section 6.3.

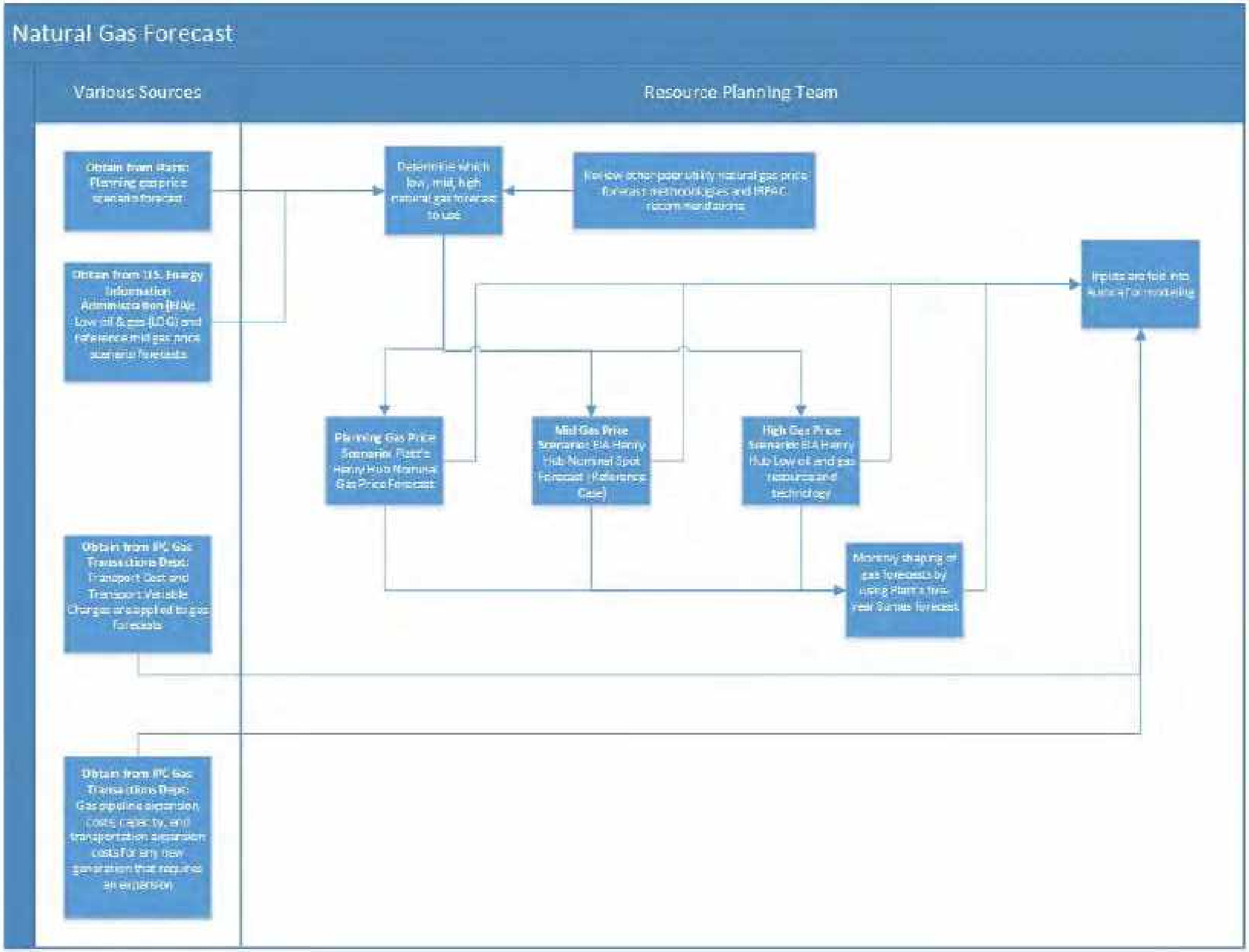

Figure 3.1 **Natural Gas Price Process Map**

3.2 Hydrology, Stream Flow Forecast Summary

3.2.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs associated with the company's hydrology and stream flow modeling, which is used to develop the forecast of hydropower generation distribution for the company's hydroelectric resources. The following summarizes the inputs and key assumptions:

Water Flow

1. Aquifer discharge levels are present-conditioned to 2009, and any changes can be superimposed on the current levels of aquifer discharge to the Snake River.

2. Variability exhibited by natural flow conditions from 1928-2009 are representative of future variability.

3. Diversion patterns have not changed significantly since 2009.

4. Current reservoir management practices will continue into the future.

5. The Enhanced Snake Plain Aquifer Model (ESPAM), run in "superposition mode," is used to reflect the incremental change in streamflow in the Snake River due to various aquifer management practices (e.g., recharge, groundwater pumping reductions, system conversions).

Future Assumptions Based on Water Flow

1. Target Control Analysis: Idaho Power's Atmospheric Sciences department performs a target control analysis to determine weather-modification impacts from the collaborative cloud seeding program.

2. Weather Modification Reach Gains: Operations Hydrology performs modeling that translates the target control analysis, which is essentially an average increase in winter season precipitation, into an incremental surface water streamflow benefit at various locations throughout the Snake River. This incremental benefit is added to the base planning model.

3. Reach Decline Trend Analysis: Operations Hydrology applies statistical tests to three reaches (Blackfoot to Neeley, Milner to Lower Salmon, and Lower Salmon to King Hill) to determine if a significant trend in aquifer discharge to the Snake River is present. If a trend is present, then it is extended through the IRP planning horizon to account for likely changes that the aquifer will experience over that time frame.

4. Surface Water Coalition (SWC)-Idaho Groundwater Appropriators (IGWA) Settlement Agreement: In 2015, a settlement between the SWC and the IGWA was reached regarding groundwater user impact to holders of senior surface water rights. The settlement agreement laid out key targets that will alter the aquifer budget in future years. The elements of the agreement are described below:

i. Groundwater Pumping Reductions – The agreement targets a volume reduction in groundwater usage. This reduction is modeled using ESPAM, and the incremental benefit is added to the base planning model.

ii. Groundwater to Surface Water Conversions – The agreement targets a volume change due to switching groundwater irrigated land to surface water supplied land, which benefits the aquifer. This change is modeled using ESPAM, and the incremental benefit is added to the base planning model.

5. Managed Aquifer Recharge: Managed aquifer recharge observations and plans are obtained from the Idaho Department of Water Resources. The volume of recharge is modeled using ESPAM, and the incremental benefit is added into the base planning model.

Generation Forecasting

1. Generation is forecast at the 50 percent exceedance level for the planning scenario, but 70 percent and 90 percent exceedance water conditions are also developed to support sensitivity analyses related to below-normal water years.
2. The historical monthly average generation from springs, based on the last 20 years, is used as a forecast for IRP modeling.

Based on the above review of key assumptions and inputs, the Hydrology and Stream Flow Sub-Team identified no concerns with the hydro forecast input to the 2019 IRP.

3.2.2. Transferring Inputs into AURORA

To ensure the hydrology and streamflow data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the hydro input data within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. During this process, a difference was identified between the source files and the AURORA input during leap years. Those differences, the review team concluded, were appropriate modifications of the input data to account for additional hydro generation hours every four years from the additional day in each leap year. Additionally, a difference was discovered between the source files and AURORA input for Brownlee, Oxbow, and Hells Canyon hydro facilities—collectively, the Hells Canyon Complex (HCC). The AURORA model holds reserves at these hydro facilities in accordance with NERC requirements. The data from the PDR580 hydro generation model, however, represents the monthly energy budget with no reserves held at the HCC. The noted deviation is variable by simulation month and year but averages 10 percent of the HCC energy budget being held in reserve by the AURORA model. The sub-team concluded that variations between PDR580 data and AURORA input were reasonable and also deemed the modeling of reserves in AURORA was appropriate. Based on the above findings, the sub-team identified no concerns with the hydrology and streamflow inputs into AURORA for the 2019 IRP.

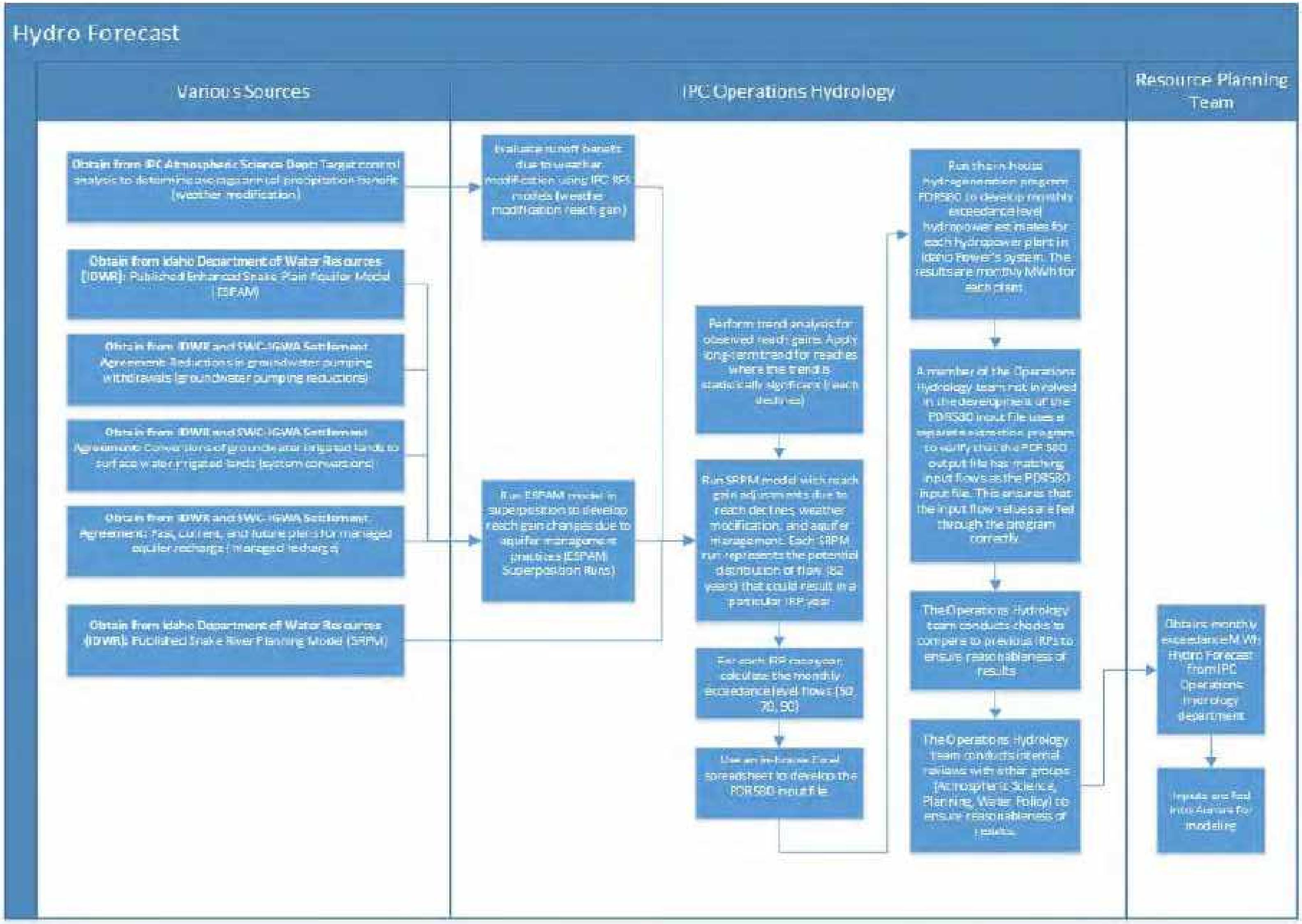

Figure 3.2 Hydrology, Stream Flow Process Map

3.3 Load Forecast Summary

3.3.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs to develop the load forecast. Although the load forecast is a complex analysis that incorporates many inputs, Step I for this input was scaled down due to a recent audit conducted by Idaho Power's Audit Services Department in the ordinary course of business. This audit involved gaining an understanding of the inputs and controls around the load forecasting process, flowcharting the process, cataloging the inputs, and mapping the inputs to validation procedures performed. This audit concluded in September 2019. Additionally, the load forecast goes through a rigorous public involvement and review process, during which time inputs and assumptions can be questioned by both internal and external stakeholders. Therefore, the Load Forecast Sub-Team determined that thorough analysis of the load forecasting process was already performed. Nevertheless, key assumptions, inputs, and sources are provided below in the interest of clarity and transparency. The following summarizes the inputs and key assumptions:

1. The company uses several primary sales models as the basis of the load forecast, which looks out over the same 20-year forecast period as the 2019 IRP. These forecast models are linked to major customer classes.

2. The residential sales forecast utilizes an end-use framework and identifies temperature-sensitive load (e.g., appliances), as well as home size. The appliances and saturations of such are calibrated to the company's service territory, as determined by Idaho Power's saturation survey administered by the Energy Efficiency Department. Appliance efficiencies and energy use per appliance are determined from shipment and forecast data compiled by Itron, which is developed from the EIA data (e.g., the Annual Energy Outlook) for the US by census region. Residential non-temperature sensitive load is identified using the same method.

3. The commercial, industrial, and irrigation sectors use a more classic econometric regressions framework. The cohort of commercial and industrial customers is further disaggregated and modeled by primary business function. Unique explanatory variables are selected for each of the modeled business functions. These explanatory variables that are used are typically economic in nature and lean on macro-economic forecasts developed by Moody's Analytics. Adjustments are assessed for each forecast period, typically using residual analysis.

4. Other key inputs to the process are customer growth (hinged on Moody's Analytics household stock forecast data), weather data (using identified National Oceanic and Atmospheric Administration (NOAA) data collection sites at Boise, Twin Falls, Ontario, McCall, Pocatello, and Ketchum), electricity prices from Idaho Power's assessment of rate base and short term fuel costs (conducted by the Regulatory Affairs and Strategic Analysis Departments), natural gas price from the long-term customer price forecast from Intermountain Gas and the natural gas price forecast (see Section 3.1 for the natural gas input assessment).

The key inputs for the load forecast come from many sources. Inputs and the process of data collection and analysis are detailed below:

1. Introduction – The energy sales and load forecast of future demand for electricity within the Idaho Power service area covers a 20-year period and is the company's estimate of the most probable outcome for sales growth during the 20-year planning period.

2. Pre-Modeling Activities

    a. Pricing Forecast

        i. Natural Gas Price Forecast – The Load Forecasting team obtains historical natural gas price and usage information from Intermountain Gas Company (IGC) and natural gas price forecasts (EIA and Platts) and creates the natural gas price forecast. The Load Forecasting team applies economic deflators from Moody's Analytics to arrive at real prices that have been adjusted for inflation. The price forecast is reviewed by the Load Research and Forecasting Manager and is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling.

        ii. Electricity Price Forecast – The Load Forecasting team obtains projected demand response irrigation rebate values from the Energy Efficiency Program Leader, four sources of revenue by major class of forecasted electricity price from the Finance Department, and forecasted electricity price increases/decreases from the Regulatory Affairs Department. The Load Forecasting team creates the electricity price forecast using this data and then applies economic deflators from Moody's Analytics to the prices to arrive at real prices that have been adjusted for inflation. The price forecast is reviewed by the Load Research and Forecast Manager and is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling.

    b. Economic Analysis – The Load Forecasting team gathers economic data (e.g., population growth, income trends, geographic GDP trends, industry groups) from third-party resources (e.g., Moody's Analytics, Woods & Poole, and others as necessary). The team performs comparative analysis on the data obtained to determine if exceptions or deviations exist that might require disaggregation of the data or evaluation of additional third-party resources. The economic data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

    c. Customer Count Forecast – The Load Forecasting team obtains growth data from Moody's Analytics, such as housing stock, mortgage rates, household data, as well as historical active customer counts. This data is used to forecast customer counts for each customer class in Idaho Power's service area. The customer count data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

d. Weather Updates – The Load Forecasting team obtains monthly kilowatt-hour (kWh) usage data and historical weather data from NOAA. Usage data is normalized using the NOAA data and is input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

e. Energy Efficiency/Demand Side Management (DSM) Forecast – The Load Forecasting team obtains the Itron SAE models with DSM assumptions, the Energy Efficiency/DSM forecast from the Energy Efficiency Department, and the third-party DSM potential study performed by Applied Energy Group (AEG). The Itron SAE models are customized with inputs more specific to Idaho Power's service area, based on the forecast provided by the Energy Efficiency Department. The information provided by the Energy Efficiency Department is compared to the AEG potential study to determine whether adjustments to the forecast are necessary. The data is then input into the Oracle Express database after review by the Load Research and Forecasting Manager. Output files from the database are fed into the MetrixND software for forecast modeling.

3. Energy (or Sales) Forecast by Customer Class

a. Net Metering Impact Adjustment – The Load Forecasting team obtains historical net metering customer counts for residential and commercial customers, as well as the "Customer by Rate" SQL query to determine the energy impact by month for customers that have switched to net metering. Using polynomial equations and rate-of-change analysis, the projected net metering customer counts are multiplied by the projected energy impact. The results are reviewed by the Load Research and Forecasting Manager, input into the Oracle Express database, and then subtracted from the residential and commercial sales forecasts.

b. Electric Vehicle (EV) Usage Forecast – The Load Forecasting team obtains vehicle registration data from the Idaho Transportation Department (ITD), which the team uses to complete a regression model that forecasts EV usage for residential and commercial customers. The results are reviewed by the Load Research and Forecasting Manager, input into the Oracle Express database, and then incorporated into the residential and commercial sales forecasts.

c. Residential Sales Forecast – The Load Forecasting team obtains the Residential SAE model from Itron for the Mountain Region geographic area, as well as the most recent Idaho Power service area saturation surveys from the Customer Research Department. The Itron SAE model is customized with inputs more specific to IPC's service area based on the saturation surveys and then is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The residential sales forecast is generated based on these items as well as the results input into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager and the net metering impact adjustment and EV vehicle usage forecast from items 3a. and 3b. above are incorporated into the sales forecast.

d. <u>Commercial Sales Forecast</u> – The Load Forecasting team obtains streetlight usage data, the Commercial SAE model from Itron for the Mountain Region geographic area, and information regarding potential new large load customers from the Business Development Department. The team also determines commercial customer segmentation (e.g., manufacturing and services). The Itron SAE model is customized with inputs more specific to Idaho Power's service area, reviewed by the Load Research and Forecasting Manager, and then input into the Oracle Express database along with the streetlighting usage forecast. Output files from the database are fed into the MetrixND software for forecast modeling. The commercial sales forecast is generated based on these items as well as the results input into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager and the net metering impact and EV vehicle usage forecast from items 3a and 3b above are incorporated into the sales forecast.

e. <u>Industrial Sales Forecast</u> – The Load Forecasting team obtains information regarding potential new large load customers from the Business Development Department. The team also determines industrial customer segmentation (e.g., manufacturing and services). The industrial modeling data is input into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The industrial sales forecast is generated based on these items as well as the results entered into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness.

f. <u>Irrigation Sales Forecast</u> – The Load Forecasting team obtains horsepower updates from the Energy Efficiency Department. Any relevant irrigation legislation updates and aquifer updates are obtained as well. This information is entered into the Oracle Express database. Output files from the database are fed into the MetrixND software for forecast modeling. The irrigation sales forecast is generated based on these items as well as the results entered into the Oracle Express database in the "Pre-Modeling Activities" section above. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness.

g. Special Contracts Sales Forecast – The Load Forecasting team obtains request letters sent and received by the Regulatory Affairs Department for customer-provided updates to forecasted large, special contract energy customer loads. The forecasts in the letters are compared to historical trends, and a follow-up discussion with the large energy customers occurs if necessary. The forecast is reviewed by the Load Research and Forecasting Manager for reasonableness and is included in the total system load forecast.

4. Hourly Peak-Load Forecast

   1. Conversion of Billed Sales Forecasts to Calendar Sales Average Load – The Load Forecasting team obtains billed sales data from AMI and applies monthly weighting factors to the data for conversion to calendar month data. The results are reviewed by the Load Research and Forecasting Manager. Then, the residential, commercial, industrial, and irrigation billed sales forecasts are converted to calendar sales forecasts using these results. These conversions are reviewed by the Load Research and Forecasting Manager and then are provided to the Resource Planning team for inclusion in the IRP.

   2. Peak Load Forecast – The Load Forecasting team obtains a 30-year historical period of average peak-day temperatures by month and runs a regression analysis on actual historical peak-day temperatures by month versus system peaks. The team also applies a loss factor (obtained from the System Planning Department) to the calendar-converted sales forecasts. These items are used to generate the peak-load forecast, based on peak-day temperatures and average load by month. The peak-load forecast is reviewed by the Load Research and Forecasting Manager.

   3. Hourly Forecast – The Load Forecasting team obtains the aggregate system energy forecast, 30-year historical weather data, calendar composition of the forecast period, and AMI and MV90 hourly data. This data is pushed through a non-linear model framework to develop heating and cooling responsiveness using derivative analysis. The 5-degree temperature slope from this derivative analysis is leveraged into a linear regression framework. The outputs from the linear regression are input into the MetrixND software. The hourly forecast is then generated using this data and the peak-load forecast from item 4b above. The hourly forecast is reviewed by the Load Research and Forecasting Manager and then is provided to the Resource Planning team for inclusion in the IRP.

5. Public Involvement Process – The Load Research and Forecasting Manager presents the output of the forecast models to the Idaho Power Finance Department's Senior Vice President, Vice President, and Director, and incorporates any changes based on financial management's expertise into the models, as needed. The updated output of the forecast models is then presented to all Idaho Power executives. If necessary, results are reviewed again based on executive management's expertise and any necessary corrections are incorporated into the model. Updated output of the forecast models is then presented to the IRPAC. If necessary, changes based on IRPAC

feedback are incorporated into the models. After the public and stakeholder input process is complete, the load forecasts are finalized for inclusion in the IRP.

6. Load Forecasting Process Flowchart – The sub-team obtained and reviewed the load forecasting flowchart from the audit conducted by Audit Services.

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, as well as the 2019 audit performed by Idaho Power's Audit Services, the Load Forecast Sub-Team identified no concerns with the load forecast input to the 2019 IRP.

3.3.2. Transferring Inputs into AURORA

To ensure that the hourly load forecast data prepared for the 2019 IRP was correctly input into the AURORA model, the sub-team exported the hourly load data within the AURORA model and tied those inputs to the source file prepared by the responsible business unit. During this review process, it was determined that the hourly load forecast data prepared for the 2019 IRP reconciled to the hourly load forecast inputs within AURORA.

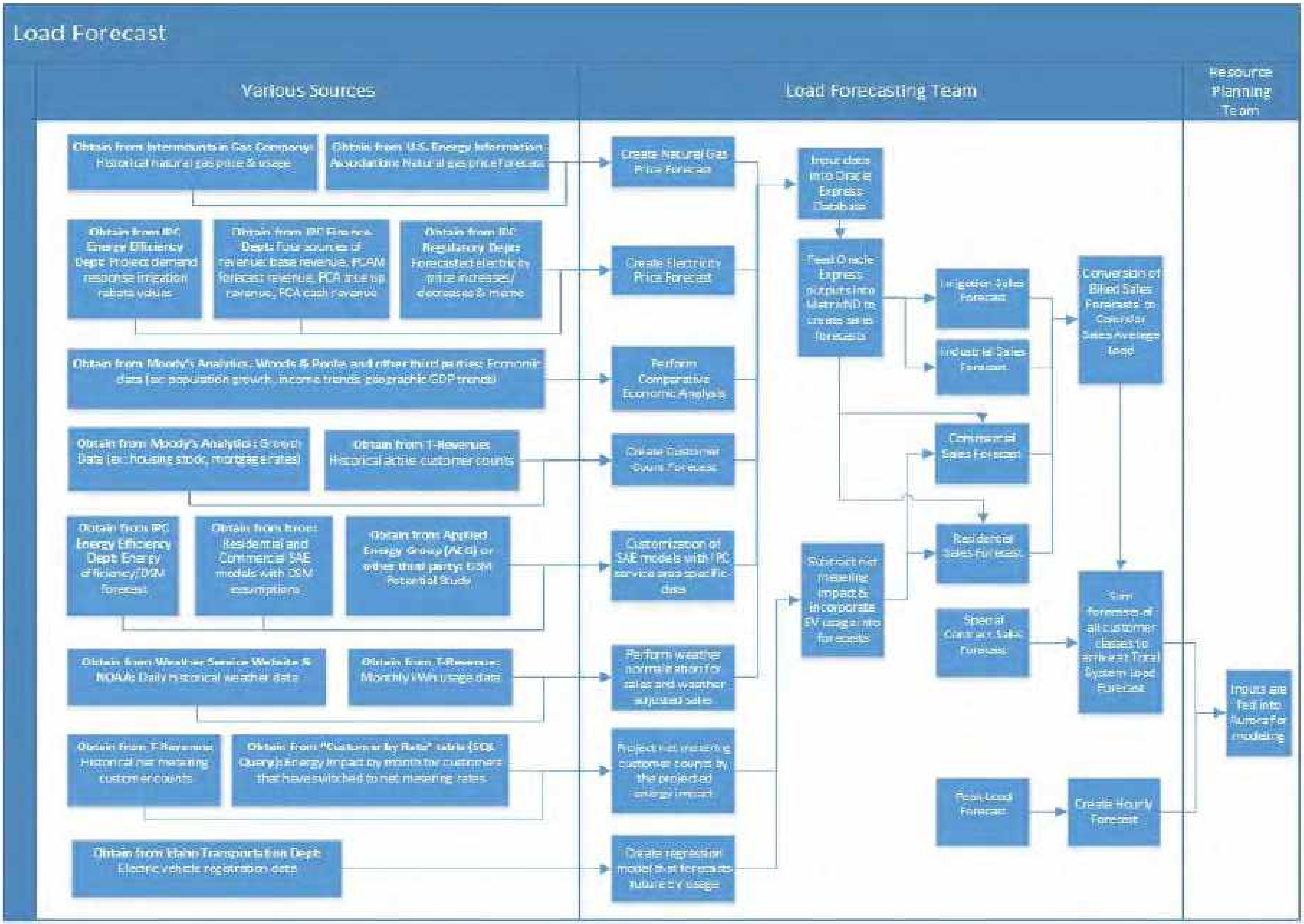

Figure 3.3 **Load Forecast Process Map**

3.4 Coal Plant Forecasts and Operations Summary

3.4.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, this sub-team assessed the supply-side inputs related to the company's coal units. The coal-related inputs included coal forecasts, plant operating parameters, variable O&M, fixed fuel costs, and non-fuel fixed costs. The following summarizes the inputs and key assumptions:

Coal Forecast for Bridger

1. The Bridger fuel forecast is derived from the Bridger Coal Company 2019-2028 budget, forecast third-party delivered coal prices, and volumes that are a component of the 2018 long-term fueling plan.

2. The delivered cost of Black Butte coal for the 2019 through 2021 period is based on actual contract rates plus estimated rail transportation charges. The Black Butte delivered coal price from 2021 is then escalated at 3 percent beginning in 2022, based on assumed annual increases in coal and transportation contract renewal rates.

3. Estimated rail transportation charges included in the delivered price of coal for 2019 are based on published Union Pacific (UP) rates at the time.

Coal Forecast for Valmy

4. The Black Butte mine is assumed to be the fuel source for Valmy due to the small volumes likely to be required through 2025 and the available capacity at the time the forecast was performed.

5. The delivered cost of Black Butte coal for 2019 is based on actual contract rates plus estimated rail transportation charges. The coal component of the Black Butte delivered coal price from 2020-2025 is escalated at 3 percent annually beginning in 2020, while the rail transportation component of the Black Butte delivered coal price is escalated at 4 percent annually beginning in 2020. These are the assumed annual increases in coal and transportation contract renewal rates.

6. The Nevada use tax is applied to the price of coal. The statutory rate of 6.85 percent was used.

7. Estimated rail transportation charges are based on published UP rates at the time.

Coal Forecast for Boardman

8. The fuel forecast is obtained from PGE for the remaining two years (2019 and 2020) of the plant's life.

Operating Parameters for Bridger

9. There are multiple operating assumptions for the Bridger plant that are used as an input to AURORA or used to develop an AURORA input: Overall plant average heat

rate, capacity, equivalent forced outage rate, fixed and variable O&M, mine decommissioning costs, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, minimum down time, and revenue requirements associated with existing and future investments.

Operating Parameters for Valmy

10. There are multiple operating assumptions for the Valmy plant that are used as an input to AURORA or used to develop an AURORA input: Overall plant average heat rate, capacity, equivalent forced outage percent, fixed and variable O&M, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, minimum down time, and revenue requirements associated with future investments.

Operating Parameters for Boardman

11. There are multiple operating assumptions for the Boardman plant that are used as an input to AURORA or used to develop an AURORA input: overall plant average heat rate, capacity, equivalent forced outage percent, variable O&M, start-up costs, minimum capacity percentage, resource end date, minimum heat rate, ramp rate, minimum run time, and minimum down time.

Capturing Fixed Fuel Costs Associated with Early Unit Shutdowns at Bridger

12. There are unavoidable fixed costs associated with Idaho Power's share of the Bridger Coal Company mine through 2028 that need to be considered in all AURORA portfolios. Because these fixed costs are a component of the fuel expense, if a shutdown of a Bridger unit were to occur prior to 2028, Idaho Power needs to ensure enough coal was burned in the remaining units to sufficiently recover these fixed costs. If it is not, then the fixed cost shortfall needs to be included as an additional cost to each portfolio.

Bridger Non-Fuel Fixed Cost Forecast

13. Bridger unit-specific forecasts of non-fuel fixed costs were developed in order to adequately capture avoidable and unavoidable costs specific to portfolios that contain proposed shutdowns of units earlier than 2034. The sources of the key data used to develop the revenue requirements are the net book value of the Bridger investments at June 30, 2018, and Bridger O&M and capital forecasts provided by PacifiCorp through 2034. Idaho Power used an internal revenue requirement model (the PWorth model) to calculate the estimated revenue requirement for each Bridger unit through 2034 to determine the fixed cost inputs for AURORA. In the portfolio costing, AURORA truncates fixed costs at the point a unit is shut down earlier than 2034, appropriately reflecting avoided O&M and forecasted capital additions. The remaining net book value is also used in the LTCE modeling as the cost hurdle associated with an early exit of a unit.

Valmy Non-Fuel Fixed Cost Forecast

14. A Valmy Unit 2 forecast of non-fuel fixed costs was developed in order to adequately capture avoidable costs specific to portfolios that contain a proposed shutdown of Unit 2 prior to 2025. The sources of the key data used included the Framework

Agreement between Idaho Power and NV Energy and the resulting exit fees, O&M expenses, and capital forecasts through 2025 provided by NV Energy. Idaho Power used the PWorth model to calculate the estimated revenue requirement associated with Valmy Unit 2 forecasted investments to determine the fixed cost inputs for AURORA. As described above, fixed costs are truncated by AURORA in the portfolio costing when Unit 2 is retired prior to 2025, appropriately reflecting avoided fixed O&M and forecasted capital costs.[1]

Sub-Team Results of Step I Review

Upon thorough review and evaluation of the source files, the sub-team confirmed the coal forecasts and resulting fuel expense were modeled appropriately and accurately, and the operating parameters were supported and reasonable. In addition, the Bridger coal forecast included enough generation in each of the portfolios to cover the fixed costs of the Bridger mine or, in the alternative, the resulting shortfall cost was added to the total portfolio costs.

A number of refinements were made to the Bridger and Valmy fixed O&M rates. As discussed below in sub-section 3.10 "Financial Inputs and Future Supply Side Resources," inconsistent financial inputs were used in the PWorth model. This model computes the Bridger and Valmy revenue requirement amounts, a component of the fixed O&M weekly $/MW rate calculation, as well as the Bridger investment net book value, a component of the decommissioning hurdle rate calculation. Both are inputs in AURORA, and it was determined the rates needed to be updated (see Section 3.10). Due to the truncation of Bridger fixed costs and Bridger common facility costs once a unit is exited, it was determined that any remaining net book value of the unit at the time of its exit must be added back to the total portfolio cost. In addition, to adequately capture savings associated with a shutdown of Valmy Unit 2 prior to 2025, it was determined that the Valmy fixed O&M rate needed to be updated.

Finally, it was determined that AURORA interpreted the variable O&M rates for Bridger, Valmy and Boardman as if they were nominal 2012 amounts and escalated them to 2019 amounts. As a result of this discovery, an adjustment was required for each of the variable O&M rates. A sensitivity analysis was performed to assess the impact on portfolio costs, and the results are discussed in Section 6.3.

3.4.2. Transferring Inputs into AURORA

To ensure the coal plant operating parameters and coal fuel forecast data prepared for the 2019 IRP were correctly entered into AURORA, the sub-team exported the input data within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. The review process determined that the majority of the coal-related inputs prepared for the 2019 IRP reconciled to the inputs within AURORA, with the exception of variable O&M costs for Bridger. Per the Bridger ownership agreement, each party is billed for its proportional share of the variable cost tied to overall plant output. Therefore, Idaho Power's share of Bridger variable O&M costs should be one-third of the total projected cost. The input

[1] Please see the discussion in Chapter 1 of the *Second Amended 2019 IRP* for discussion of Valmy Unit 2 exit timing.

value within AURORA did not reflect the Idaho Power’s one-third share. As a result, a sensitivity analysis was performed with the appropriate variable O&M costs entered in AURORA. The results of the sensitivity analysis are provided in Section 6.3. Additionally, the review process identified the Bridger Unit 4 fixed O&M rate was incorrectly linked to the Bridger Unit 3 fixed O&M costs within AURORA. This link was updated in conjunction with the update to Bridger fixed O&M rates discussed above.

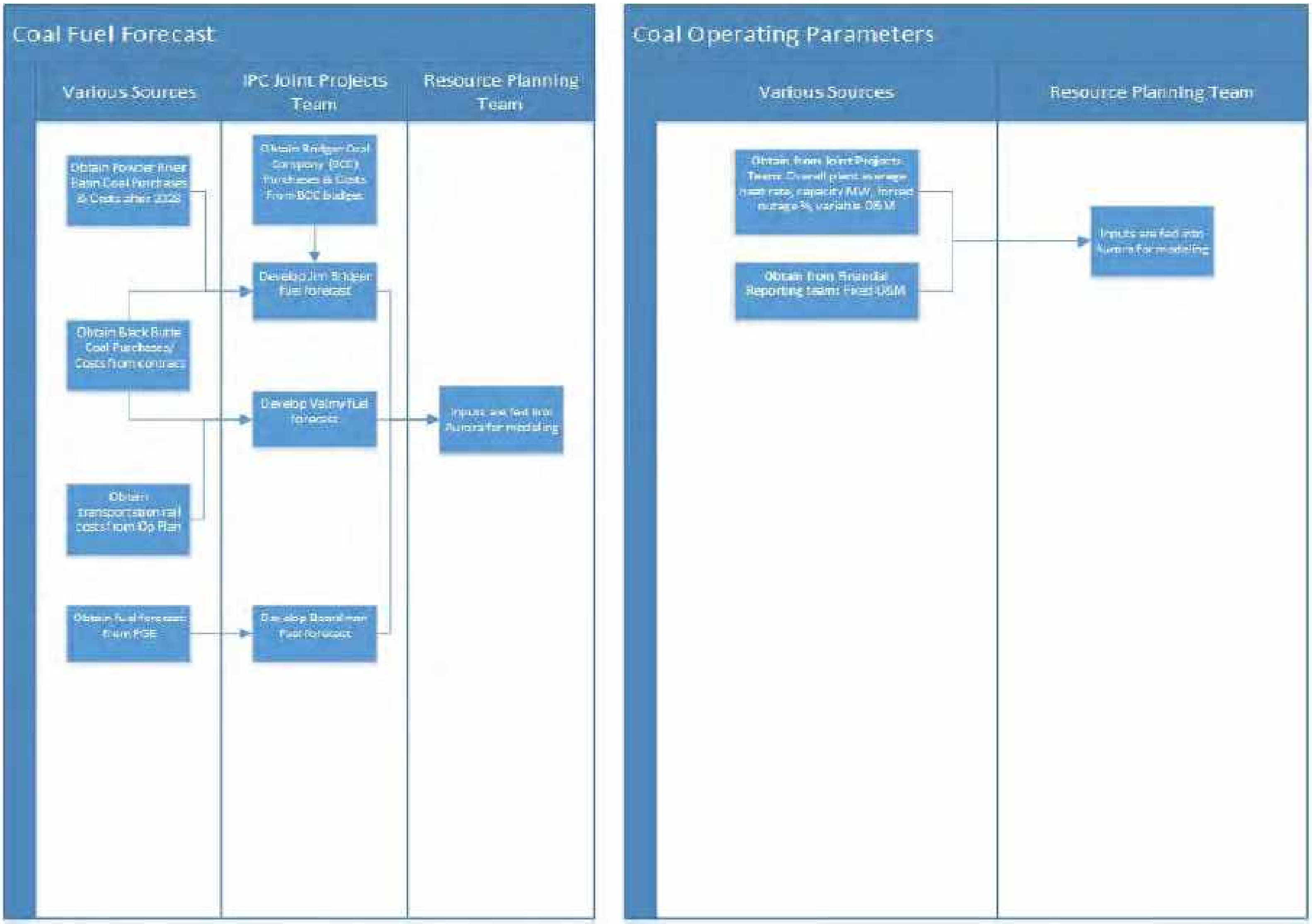

Figure 3.4 Coal Plant Forecasts and Operations Process Map

3.5 Natural Gas Plant Inputs Summary

3.5.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the supply-side inputs related to the company's natural gas plants. The natural gas plant-related inputs included plant operating characteristics and fixed and variable O&M costs. The following summarizes the inputs and key assumptions.

The Natural Gas Plant Sub-Team, along with a company subject matter expert, evaluated the operating characteristics of each of Idaho Power's existing natural gas plants (Langley Gulch, Danskin, and Bennett Mountain) including: heat rate, capacity, capacity monthly shape, monthly variable O&M, startup costs, ramp rate, min up time, and min down time. The team noted the following inputs were pre-populated in AURORA by Energy Exemplar using publicly available information: Non-cycling dispatch price adder, minimum capacity, heat rate at minimum capacity, and emission rates.

Sub-Team Results of Step I Review

The sub-team identified two items that could have an impact on the IRP relating to plant operating characteristics:

- Natural gas plant maintenance costs associated with the peaker plants were captured only as a variable cost applied directly to the runtime of the unit. Startup costs were included in the same way (i.e., variable runtime costs), which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected.
- The ramp rate input for Langley Gulch was set to 100 percent, which does not accurately reflect actual operations of the plant. The sub-team determined that a 60-percent ramp rate would better reflect plant operations.

3.5.2. Transferring Inputs into AURORA

To ensure that the natural gas plant operating parameters prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the natural gas plant input data within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During the review process, it was determined that most natural gas plant inputs prepared for the 2019 IRP reconciled to the natural gas plant inputs within AURORA. The inputs that did not reconcile included startup costs for each of the company's natural gas peaker plants as well as the ramp rate for Langley Gulch. As a result, sensitivity analyses were performed with the appropriate natural gas plant inputs in AURORA. The results of the sensitivity analyses are provided in Section 6.3.

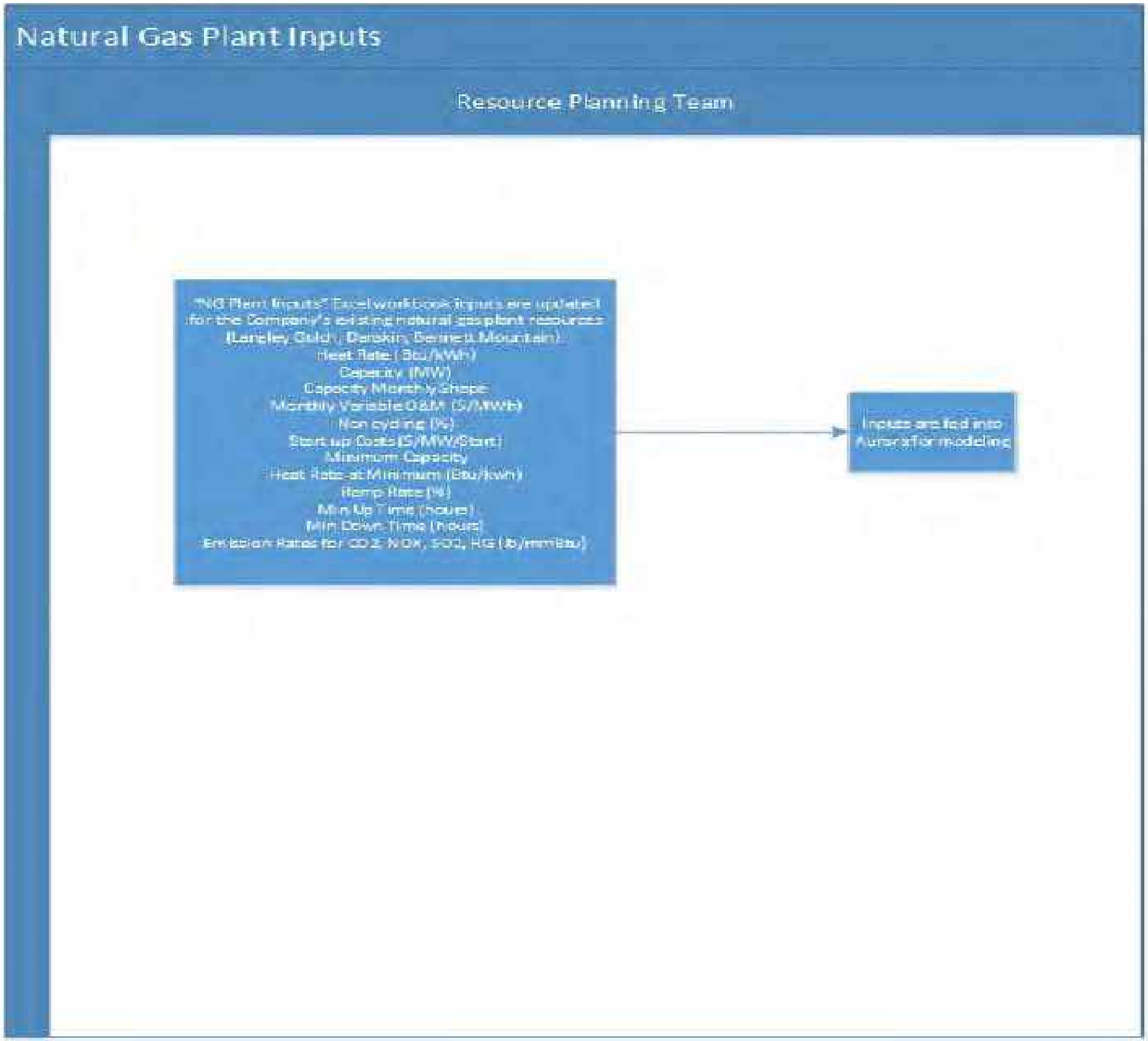

Figure 3.5 Natural Gas Plant Process Map

3.6 CSPP and PURPA Inputs Summary

3.6.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed inputs related to Idaho Power's cogeneration and small power production (CSPP) and PURPA forecast. The following summarizes the inputs and key assumptions:

Forecast Avoided Cost Rates

1. Contract rates for contracts with annually adjusted rates are forecast at the actual rate at the time of the forecast through the forecast period.
2. Current IPUC or OPUC rates for a given resource type can be used.
3. Contract rates for Power Purchase Agreements (PPA) utilize rates from the previous 12 months without escalation over the forecast period.

Forecast Generation

4. Estimated Generation: Initial contract estimates are used for new contracts, the most recent 12-month history, or the arithmetic mean of the last five years of generation. Normally, the arithmetic mean of the last five years of generation is used. Estimates can be adjusted based on knowledge of the project and resource type.
5. Included Energy Service Agreements (ESA) and PPAs: New projects are included in the forecast upon signing of a contract, as the company is legally bound to purchase power at that point.
6. All contracts are forecast to be replaced upon expiration of the existing contract except for wind contracts. The company is unable to accurately predict whether wind Qualifying Facilities (QF) will choose to invest in repowering due to several factors.
7. Average estimated generation is allocated to Heavy Load (HL) at 56 percent, unless it is determined a different proportion should be used. Solar projects require a different HL component. Average estimated generation for solar has been calculated to be 84 percent. Based on a review of 12x24 (months per year by hours per day) solar generation profiles, all solar generation falls within the hours of 6 a.m. and 10 p.m. On Sundays and Holidays, solar generation is considered Light Load (LL).

Sub-Team Results of Step I Review

Based on the above review of key assumptions and inputs, the CSPP/PURPA Forecast Sub-Team identified no concerns with the various forecasts input to the 2019 IRP.

3.6.2. Transferring Inputs into AURORA

To ensure that the CSPP and PURPA data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the CSPP and PURPA data within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the CSPP and PURPA forecast data prepared for the 2019 IRP reconciled to the inputs within AURORA. No further action was deemed necessary.

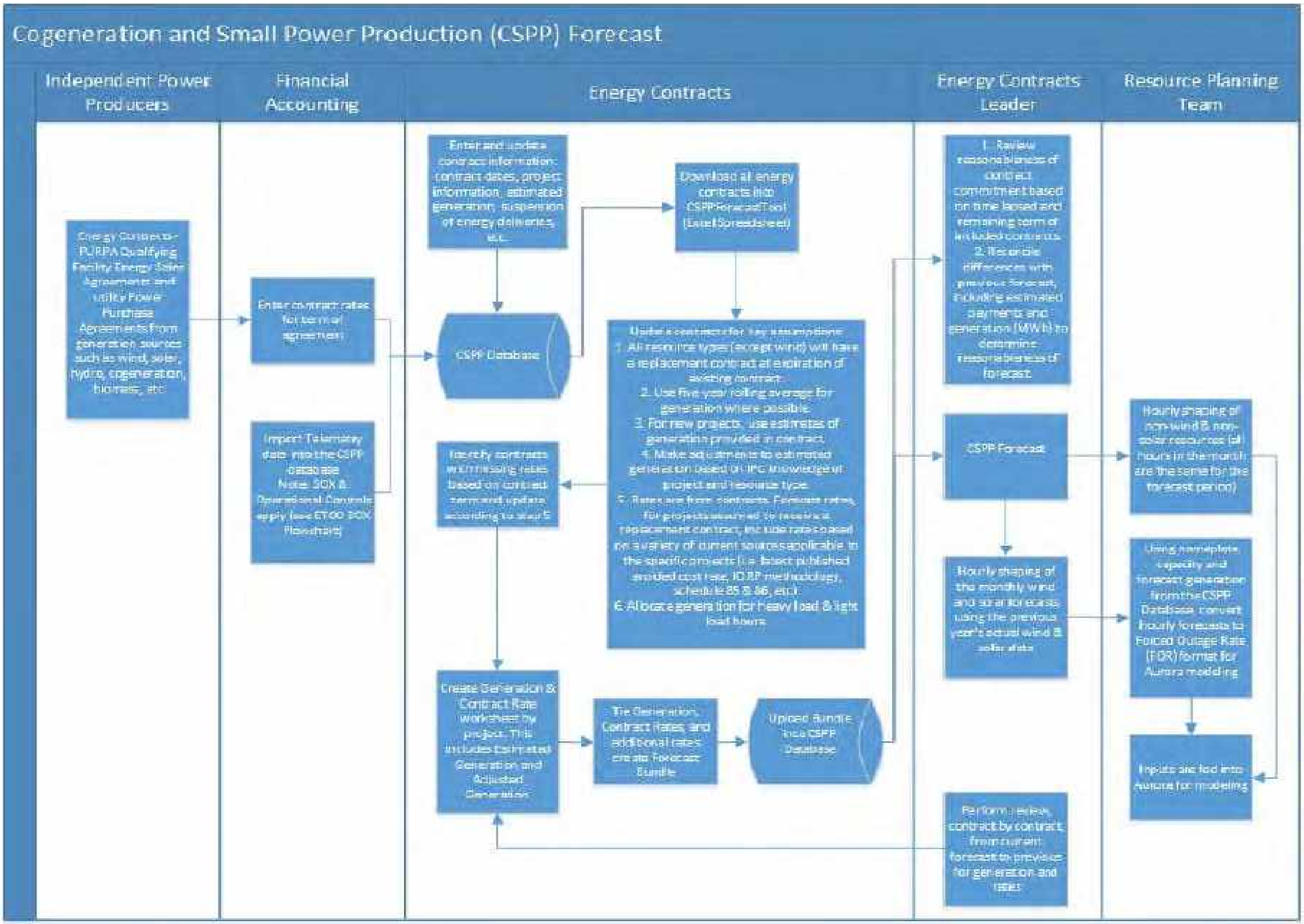

Figure 3.6 CSPP and PURPA Inputs Process Map

3.7 Demand Response and Energy Efficiency

3.7.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, the Demand Response (DR) and Energy Efficiency (EE) Sub-Team assessed forecast inputs related to Idaho Power's DR and EE programs. The following summarizes the inputs and key assumptions:

Demand Response

1. Capacity for the company's three DR programs (Residential A/C Cool Credit Program, Irrigation Peak Rewards Program, and Commercial/Industrial Flex Peak Program) is estimated using the prior year's maximum calculated capacity and customer dispatch shape from the previous summer (detailed in the DSM report, which is reviewed internally and filed with both commissions each March).

2. A DR event on the peak day in June, July, and August are incorporated into the hourly load forecast for each year during the 20-year planning period. Hourly shaping factors are then applied over a target range of three hours prior to the peak hour and three hours subsequent to the peak hour for each event (the hourly shaping factors are consistently applied to all DR events over the 20-year period). The hourly shaping is then fed into AURORA. The sub-team discussed how the Resource Planning team reviews a graphical representation of a peak day (including a DR event with hourly shaping applied) and concluded that the hourly shaping of DR is reasonable.

Energy Efficiency

Company data (including sales and peak data, customer usage data, residential survey data, sales and load forecast data, program participation data, and avoided cost data) is provided to a third party—currently, Applied Energy Group (AEG)—to perform a DSM Potential Study biennially. Idaho Power then assumes AEG's energy efficiency forecasts in the IRP.

1. <u>Energy Efficiency bundles:</u> Idaho Power contracts with a third party—currently AEG —on a biennial basis to perform a DSM Potential Study that evaluates the potential amount of achievable and economic energy efficiency. The DSM Potential Study considers market adoption, customer preferences for energy-efficient technologies, and expected program participation. In 2019, AEG provided bundles of technically achievable energy efficiency, bundled at varying costs, in addition to the legacy DSM Potential Study output. These data associated with the potential amounts came directly from AEG and were input into AURORA without issue.

2. <u>AEG bundles to load forecast</u>: AEG created a total of 11 energy efficiency bundles. In the load forecast used in the 2019 IRP, Idaho Power assumed a level of energy efficiency. The review sub-team found that the input table for energy efficiency bundles showed the level of energy efficiency included in the load forecast compared to the level of energy efficiency contained in each of the 11 energy efficiency bundles provided by AEG. The levels in bundles 1 through 7 were included in the load forecast, leaving bundles 8 through 11 as inputs into AURORA. The review team

confirmed the assignment of the bundles, both in the load forecast and as inputs to AURORA, was appropriate.

3. Cost Savings: AEG provided the cost savings related to each energy efficiency bundle, with the costs for each of the bundles over the 20-year planning period using a 2.1 percent assumed escalation factor. These data came directly from AEG. The team noted, however, that AEG's applied 2.1 percent assumed escalation factor was inconsistent with the 2.2 percent assumed escalation factor used for other inputs within the IRP process. The team resolved that the 2.1 percent factor was reasonable as it was the latest factor when it was provided to AEG. Preparation of the 2019 IRP had not begun yet—and it was during the 2019 IRP preparation that a 2.2 percent factor was selected for other inputs. As a result, the team did not deem it necessary to perform a sensitivity analysis.

Sub-Team Results of Step I Review

Demand Response

Based on the above review of key assumptions and inputs, the Demand Response & Energy Efficiency Sub-Team identified no concerns with the Demand Response inputs to the 2019 IRP.

Energy Efficiency

Based on the above review of key assumptions and inputs, the Demand Response & Energy Efficiency Sub-Team identified no concerns with the Energy Efficiency inputs to the 2019 IRP.

3.7.2. Transferring Inputs into AURORA

To ensure the Demand Response and Energy Efficiency data prepared for the 2019 IRP were correctly entered into the AURORA model, the sub-team exported the Demand Response and Energy Efficiency inputs within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the Demand Response and Energy Efficiency data prepared for the 2019 IRP reconciled to the inputs within AURORA.

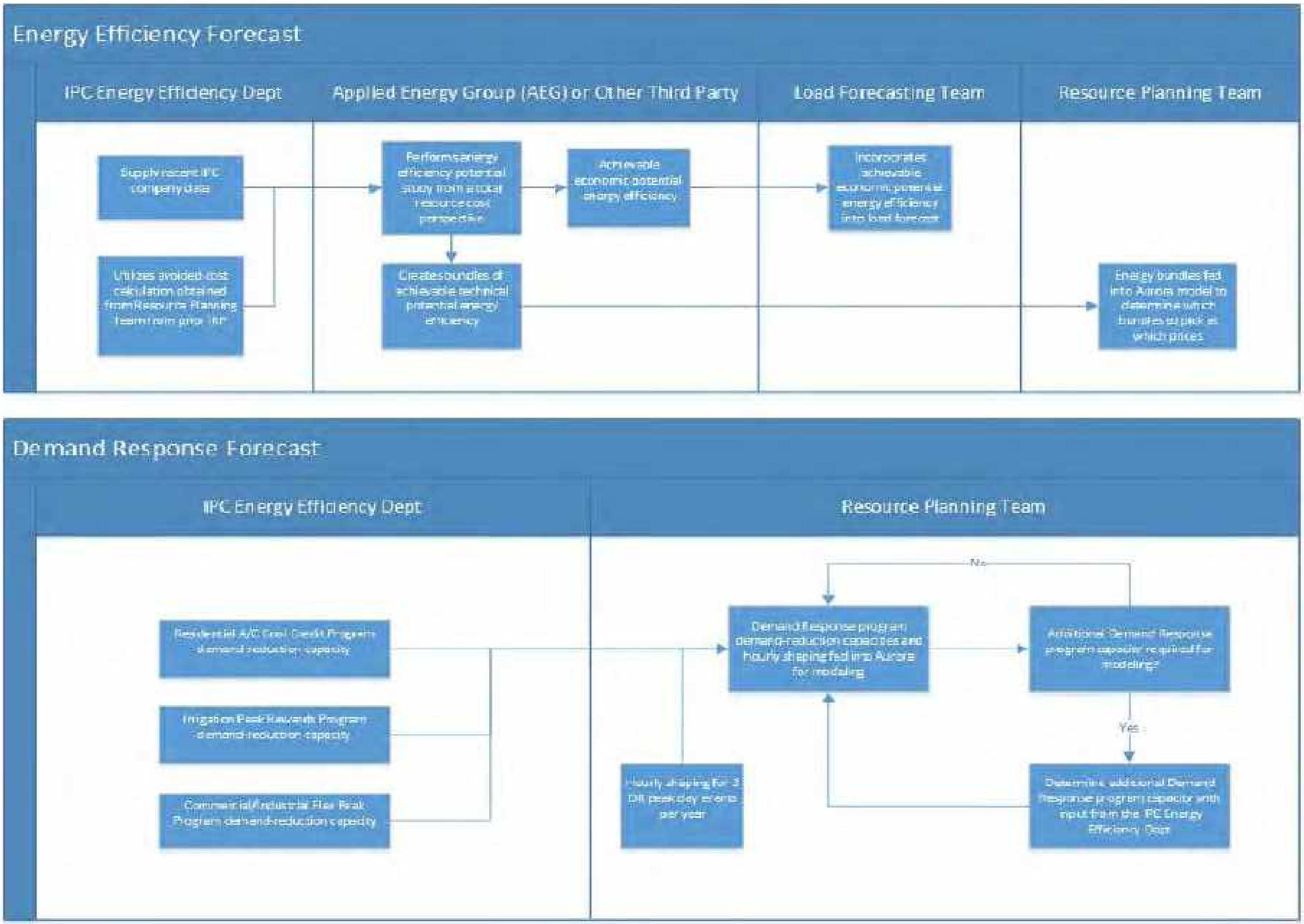

Figure 3.7 Demand Response and Energy Efficiency Process Map

3.8 Transmission Inputs Summary

3.8.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs related to the transmission system forecast. The transmission-related inputs included transfer capacity, including the impact of losses and wheeling rates. The following summarizes the key assumptions and inputs:

Transfer Capacity

1. Available transfer capacity (ATC) is determined by starting with the transmission lines' total transfer capacity and then removing the transmission that has been forecasted by month by other users such as Bonneville Power Administration. Also considered in ATC is the dispatch of external generation such as Valmy, Boardman, and Jim Bridger. The loss rate is the Joule effect, wherein energy losses occur as current and impedance generate heat in the conductors, which can impact on-line transmission capacity.

2. Wheeling rate by line is the cost due to the transmission owner for use of the transmission facility.

3. Available capacity for some lines is forecast by month due to the usage of the line and reflects the fluctuating generation of a resource attached to the line.

Transmission Operating Characteristics

1. The transmission system forecast prepared for the 2019 IRP includes transmission capacity, loss factors, and wheeling rates for each transmission line. For lines with capacities that vary with time, the transmission capacity was calculated by starting with the maximum total capacity and then subtracting a forecast of existing transmission commitments to arrive at the ATC.

Sub-Team Results of Step I Review

The sub-team reviewed the transmission system forecast prepared for the 2019 IRP, which resulted in adjustments to the loss rate, wheeling rate, and capacity for some of the transmission lines. Therefore, it was determined that sensitivity analyses should be conducted to determine the impact of the adjustments. The results of the sensitivity analyses are provided in Section 6.3.

3.8.2. Transferring Inputs into AURORA

To ensure that the transmission data prepared for the 2019 IRP was correctly input into the AURORA model, the sub-team exported a sample of transmission line data within the AURORA model and tied those inputs to the source file prepared by the responsible business unit.

It is important to understand that the IRP Planning Team individually models each transmission line with capacity in/out within AURORA. Due to the complexity, and that each individual line is a separate table in AURORA, the sub-team reviewed a sample of three transmission line inputs into AURORA: The ENPR line, Path 16, and B2H. During this review process, it was determined that the transmission system forecast data prepared for the 2019 IRP reconciled with the inputs into AURORA.

Sub-Team Results of Step II Review

The IRP Review Team found that the transmission capacity for the selected three lines was properly input into AURORA. The changes to the loss factor, wheeling rate, and capacity identified during the Step I Review were evaluated in a sensitivity analysis. The results of the sensitivity analysis are provided in Section 6.3.

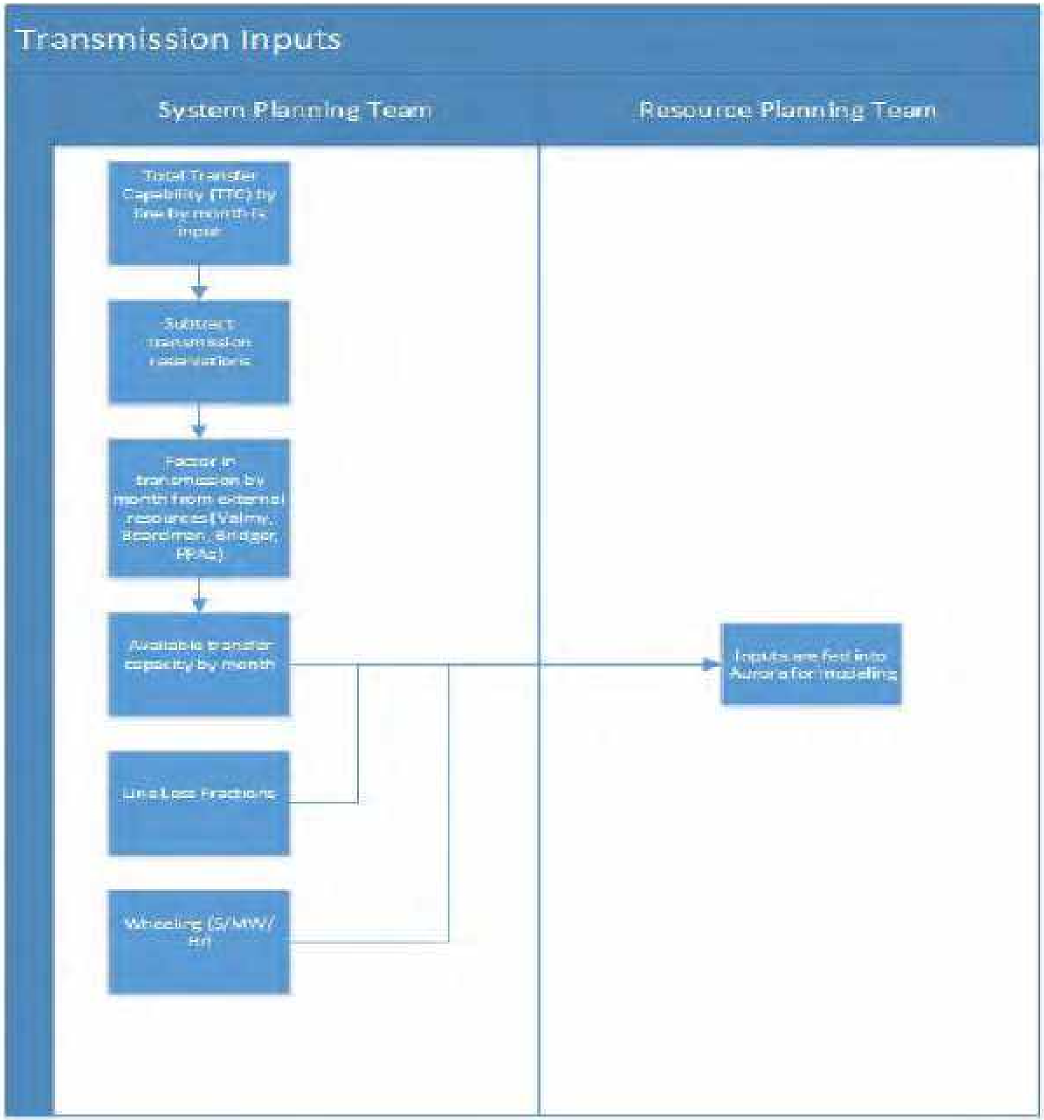

Figure 3.8 Transmission Inputs Process Map

3.9 Boardman to Hemingway Inputs Summary

3.9.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the financial assumptions related to the B2H transmission line. The general transmission system assumptions were evaluated in section 3.8 above. The following summarizes the key assumptions and inputs:

1. Because the same financial assumptions used for supply-side resources apply to the B2H transmission line costs, the pertinent discussion and review of those inputs are discussed in section 3.10 below.

2. Transmission revenue credits are included as a credit in the B2H cost calculations. They are estimated using Idaho Power's transmission rate forecast. The forecast includes the latest-year Federal Energy Regulatory Commission (FERC) Form 1 inputs to calculate the current Idaho Power transmission rate, and, for most components, creates an average inflation rate using the last three years of historical actuals to forecast the transmission rate into future years. If there is a known major change to any of the formula rate components (e.g., an asset swap), an adjustment would be made for that specific transaction. The B2H final build costs are added in year 2026, when the asset is expected to be in service in transmission plant. These costs are obtained from the Power Supply department. The resulting Idaho Power transmission rate forecast includes the change to transmission revenues expected with the addition of B2H.

Sub-Team Results of Step I Review

Notwithstanding the findings within the Financial Inputs Sub-Team (Section 3.10), the B2H Sub-Team found that the revenue credits were reasonable and properly included in the B2H PWorth model.

3.9.2. Transferring Inputs into AURORA

As discussed in Section 3.8.2, the B2H transmission capacity entered into AURORA was reviewed and reconciled with the transmission system data prepared for the 2019 IRP. The costs for B2H are not entered into AURORA but are manually added to the portfolio costs after the portfolio costs are exported from AURORA. The B2H costs are only added to the portfolios in which B2H is identified as a resource.

To test the addition of the B2H costs into portfolios, the planning gas and planning carbon scenario was selected for review. To add the B2H costs into the portfolio, the net present value (NPV) of the cost of the resource was determined. This was calculated by multiplying the levelized capacity cost (calculated in the PWorth model) by the capacity of the resource beginning in the year the resource is placed in service to determine the annual cost of the resource. The NPV of the B2H costs are calculated based on the annual costs of the resource for the 20-year IRP planning period. The sub-team reviewed the calculation and reconciled to the levelized capacity cost figure provided by Financial Accounting and verified that the proper discount rate of 7.12 percent was used. The total B2H cost (NPV) was then added to the total portfolio cost of each of the identified portfolios (NPV).

Sub-Team Results of Step II Review

The sub-team noted the B2H costs were properly added to the portfolio costs. However, differences were identified in levelized capacity cost (mills/kW/month) provided to the planning team due to different property tax and insurance rates. Therefore, a sensitivity analysis was conducted by updating these rates to obtain the new levelized capacity cost. Refer to Section 6.3 for results.

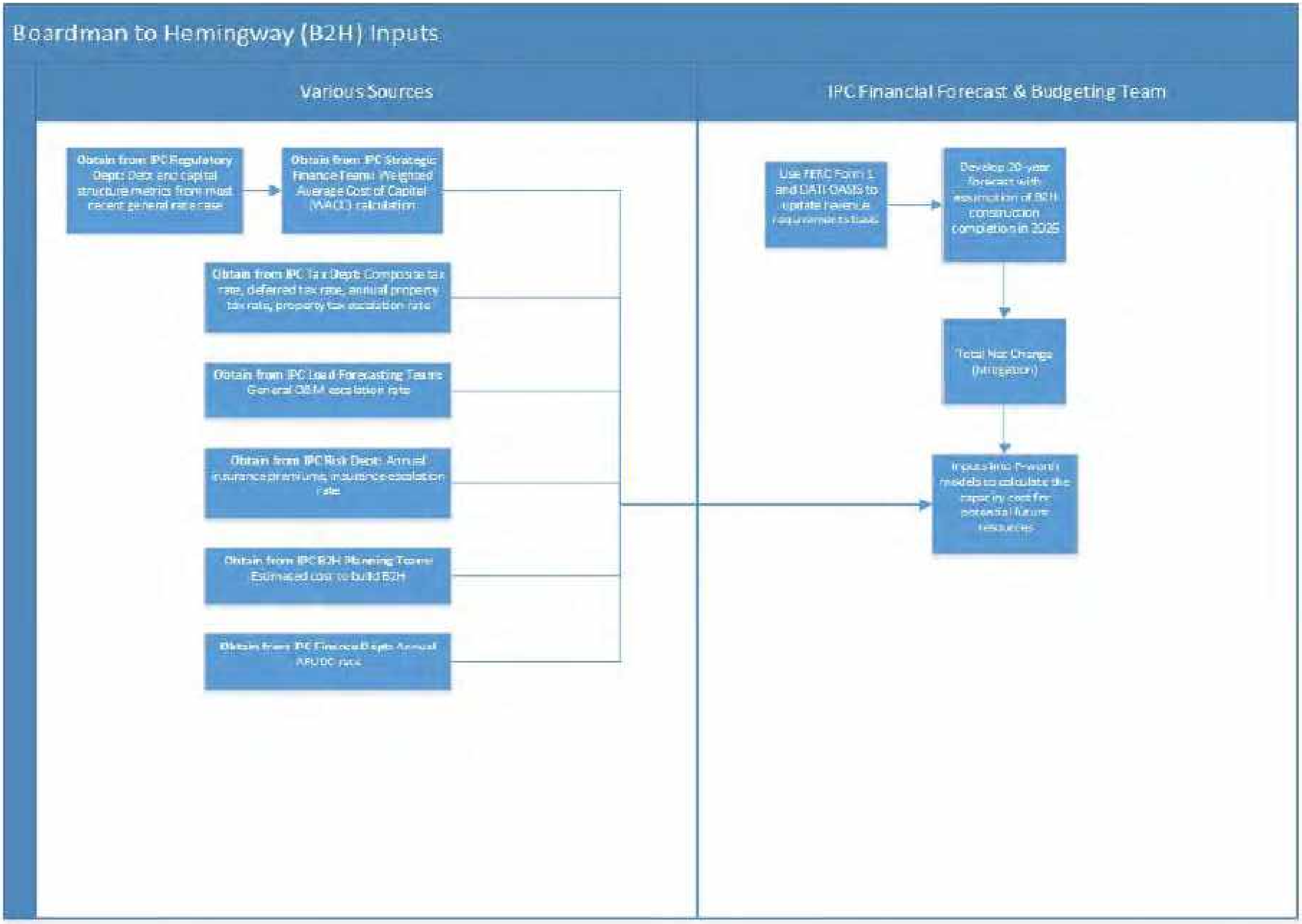

Figure 3.9 **Boardman to Hemingway Inputs Process Map**

3.10 Financial Inputs and Future Supply-Side Resources Summary

3.10.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team reviewed the financial inputs that were used to determine the costs for supply-side resources for accuracy. The following summarizes the key assumptions and inputs:

1. The discount rate (Weighted Average Cost of Capital) was determined to be 7.12 percent. This rate was determined by calculating the composition of debt, preferred stock, and common stock.
2. The corporate tax rate of 25.74 percent reflects the change in tax laws that occurred in 2018.
3. The deferred tax rate for Contributions in Aid of Construction (CIAC) and Construction Work in Progress (CWIP) was determined to be 21.30 percent.
4. The general O&M escalation rate is determined by the Load Forecasting department. This rate was analyzed using both US Bureau of Economic Analysis and Moody's Analytics Consumer Price Indices (CPI). The Moody's CPI future 20-year rate for 2018-2037 was used for the IRP general O&M escalation rate of 2.2 percent.
5. Property taxes are derived from the property tax escalation rate and the annual property tax rate as a percentage of investment. The applied rates to supply-side resources are the State of Idaho rate. This rate was determined to be appropriate because even though the exact location where assets might be built is unknown, the majority of Idaho Power's service territory is in Idaho (excluding B2H, which is addressed below).
6. Insurance costs are derived from an insurance escalation rate and annual insurance premiums as a percentage of investment. The applied rates to supply-side resources are based on the Insurance & Risk Management Advisor's knowledge of Idaho Power's current and past escalation rates and premiums.
7. The Allowance for Funds Used During Construction (AFUDC) rate is obtained from the Financial Reporting team. The rate used in the IRP is the current month AFUDC rate when the study was performed.

The financial assumptions are inputs used by multiple departments to forecast and model data throughout the IRP process. Therefore, the team ensured the rates were accurate and consistently applied throughout the review process.

The sub-team reviewed each of the financial assumptions with subject matter experts to verify the accuracy of the values used in the 2019 IRP. The values for most assumptions were validated and deemed reasonable. The following financial assumptions warranted additional review:

- Annual Property Tax Rates – Upon review of the property tax rates used to calculate the capacity costs of supply-side resources, the annual rate applied in the 2019 IRP was deemed stale. Through discussions it was determined this rate was rolled forward from the 2017 IRP and should be updated to 0.49 percent to reflect current Idaho property tax rates. The Idaho rate was used since the majority of the company's property is located in Idaho; an exception to this is B2H. Because the B2H line is primarily located in Oregon, the company determined that a blended property tax rate would better reflect the plant investment by jurisdiction. Based on this principle, property tax escalation rate applied to B2H should reflect Oregon trends as well.
- Annual Insurance Rates – Upon review of the annual insurance rate used, it was determined that a rate of 0.31 percent was being used, but the company's subject matter expert determined the rate should be 0.03 percent.

Sub-Team Results of Step I Review

The sub-team identified two areas that could have potential impacts on the IRP: Annual property tax rate (% of investment) and the annual insurance premium. A sensitivity analysis was performed for each, and the results are discussed in Section 6.3.

3.10.2. Transferring Inputs into AURORA

To ensure the data prepared for the 2019 IRP were correctly input into AURORA, the sub-team exported the financial inputs within the AURORA model and tied those inputs to the various source files prepared by the responsible business unit. The financial inputs within the AURORA model include the discount rate, inflation factor and levelized costs of future supply-side resources. During this review process, it was determined that the financial inputs prepared for the 2019 IRP reconciled to the inputs within AURORA.

Sub-Team Results of Step II Review

The sub-team noted the future supply-side resource costs were properly added to the portfolio costs. Changes to the levelized mills/kW/month costs were included in a sensitivity analysis by updating the property and insurance rates to obtain the new levelized capacity costs and the results are discussed in Section 6.3.

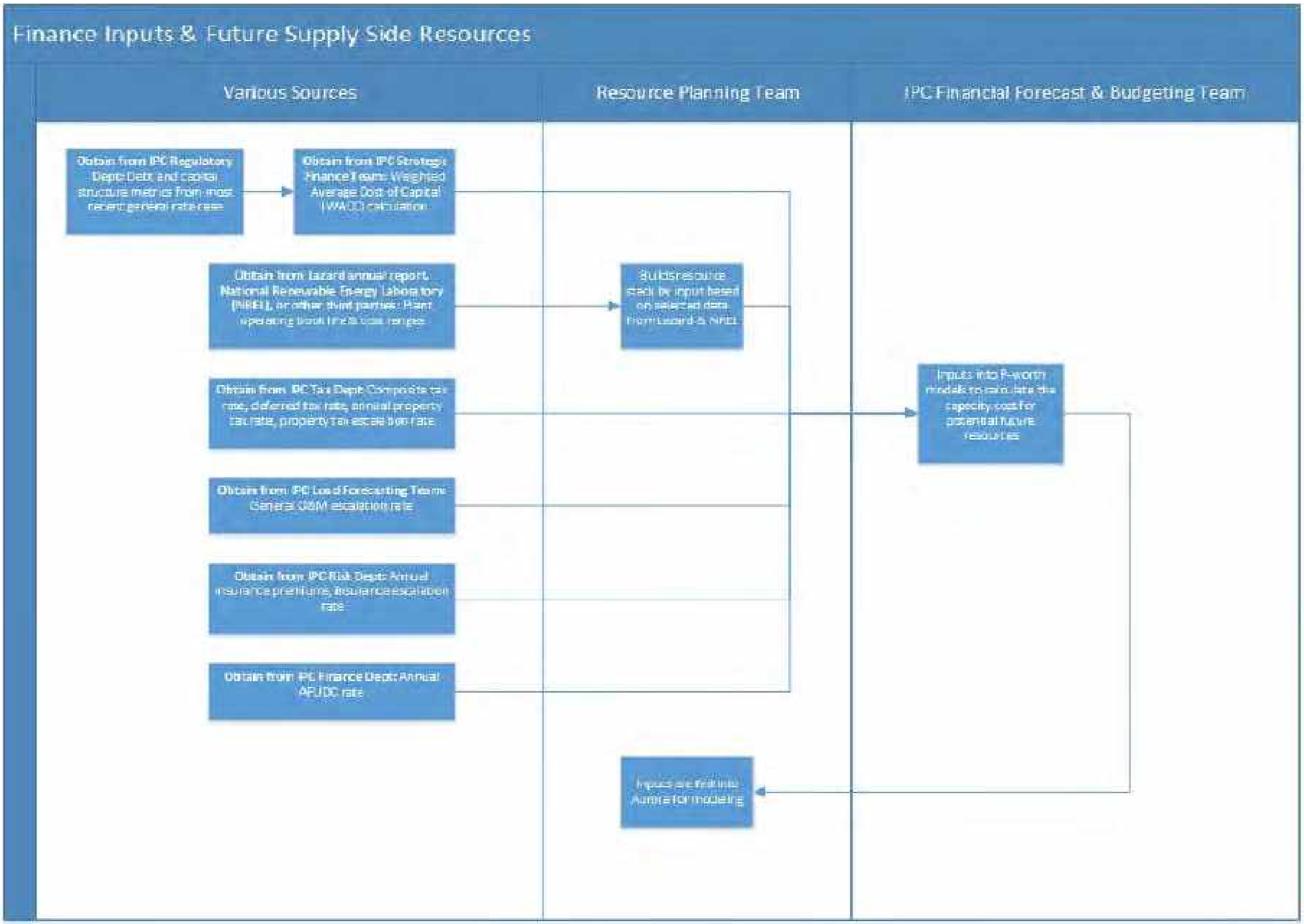

Figure 3.10 **Financial Inputs/Future Supply Side Resources Process Map**

3.11 Reliability Inputs Summary

3.11.1. Inputs and Assumptions

As part of the full examination of input data related to the IRP process, a sub-team assessed the inputs related to system reliability. The reliability inputs included regulating reserve and reserve carrying capacity by resource. The following summarizes the key assumptions and inputs:

Seasons

1. Seasons were defined as follows:
   a. Winter = December, January, February
   b. Spring = March, April, May
   c. Summer = June, July, August
   d. Fall = September, October, November

Estimation of RegUp/RegDn for Wind:

2. The binning by Two Hours Ahead (2HA) forecast was defined as follows:
   a. Bin 1: 2HA wind forecast < 143 MW
   b. Bin 2:

Estimation of RegUp/RegDn for Solar:

5. Solar binning for winter was defined as follows:
   a. Bin 1: 0 MW-0.1 MW
   b. Bin 2: 0.1 MW-10 MW
   c. Bin 3: 10 MW-60 MW
   d. Bin 4: 60 MW-110 MW
   e. Bin 5: 110 MW and above
6. Solar binning for spring was defined as follows:
   a. Bin 1: 0 MW-0.1 MW
   b. Bin 2: 0.1 MW-10 MW
   c. Bin 3: 10 MW-135 MW
   d. Bin 4: 135 MW-220 MW
   e. Bin 5: 220 MW+
7. Solar binning for summer was defined as follows:
   a. Bin 1: 0 MW-0.1 MW
   b. Bin 2: 0.1 MW-10 MW
   c. Bin 3: 10 MW-185 MW
   d. Bin 4: 185 MW-245 MW
   e. Bin 5: 245 MW+
8. Solar binning for fall was defined as follows:
   a. Bin 1: 0 MW-0.1 MW
   b. Bin 2: 0.1 MW-10 MW
   c. Bin 3: 10 MW-115 MW
   d. Bin 4: 115 MW-180 MW
   e. Bin 5: 180 MW+

The company developed approximate regulation rules for use in the 2019 IRP based on historical Pi data (generation data obtained from SCADA) by season for the prior year. Regulation Up (RegUp) and Regulation Down (RegDn) percentages were assigned by hour/MW bin for load, wind, and solar. These percentages are ultimately entered into AURORA. During the review, the sub-team noted the calculation for RegDn percentages referenced the RegUp allocation factor instead of the RegDn allocation factor. The team determined a sensitivity analysis should be performed for impact evaluation.

To inform a comparative evaluation of the regulation rules developed for the 2019 IRP, Idaho Power reviewed the regulation percentages determined as part of the company's 2018 Variable Energy Resource Study (VER Study). Idaho Power's VER Study determined the impacts and costs associated with integrating variable energy resources, such as wind and solar, without compromising reliability. The study was developed in coordination with a group of Idaho Power subject matter experts and external experts (including members of the IPUC, OPUC, Idaho National Laboratory, Northwest Power and Conservation Council, Renewable Northwest, and the University of Idaho).

The integration costs in the VER Study provided a comparative evaluation of variable generation resources to other resource options. The tables within the VER Study provide percentages of seasonal RegUp (the generating capacity that can be ramped up intra-hour to respond to undersupply conditions) and RegDn (the generating capacity that can be similarly ramped down to respond to oversupply conditions) by "bin" for load, wind, and solar. The Reliability Sub-Team noted these percentages aligned with the percentages prepared for the 2019 IRP.

Another key reliability input reviewed by the sub-team was reserve carrying capacity by resource. This listing within AURORA is carried over from one IRP to the next given that a unit's ability to carry reserves does not change between IRP cycles. During the sub-team's review of this listing, it was noted that Valmy Units 1 and 2 were listed as having the ability to provide reserve carrying capacity; however, Idaho Power's Load Serving Operations (LSO) department noted these units do not currently provide any reserves. The Reliability Sub-Team determined a sensitivity analysis should be performed.

Sub-Team Results of Step I Review

The sub-team identified two items that could have impacted the IRP including the allocation factor used for the RegDn percentages and the reserve carrying capacity of Valmy Units 1 and 2. A sensitivity analysis relating to these items was performed. The results are discussed in Section 6.3.

3.11.2. Transferring Inputs into AURORA

To ensure the data prepared for the 2019 IRP was correctly entered into AURORA, the sub-team exported the reliability inputs within the AURORA model and tied those inputs to the source files prepared by the responsible business unit. During this review process, it was determined that the reliability inputs prepared for the 2019 IRP reconciled to the inputs within AURORA. As noted above, during the Step 1 review process the sub-team identified necessary corrections to the allocation factor used for the RegDn percentages, as well as the reserve carrying capacity of Valmy Units 1 and 2. These adjustments were entered in AURORA and sensitivity analysis was performed, as discussed further in Section 6.3.

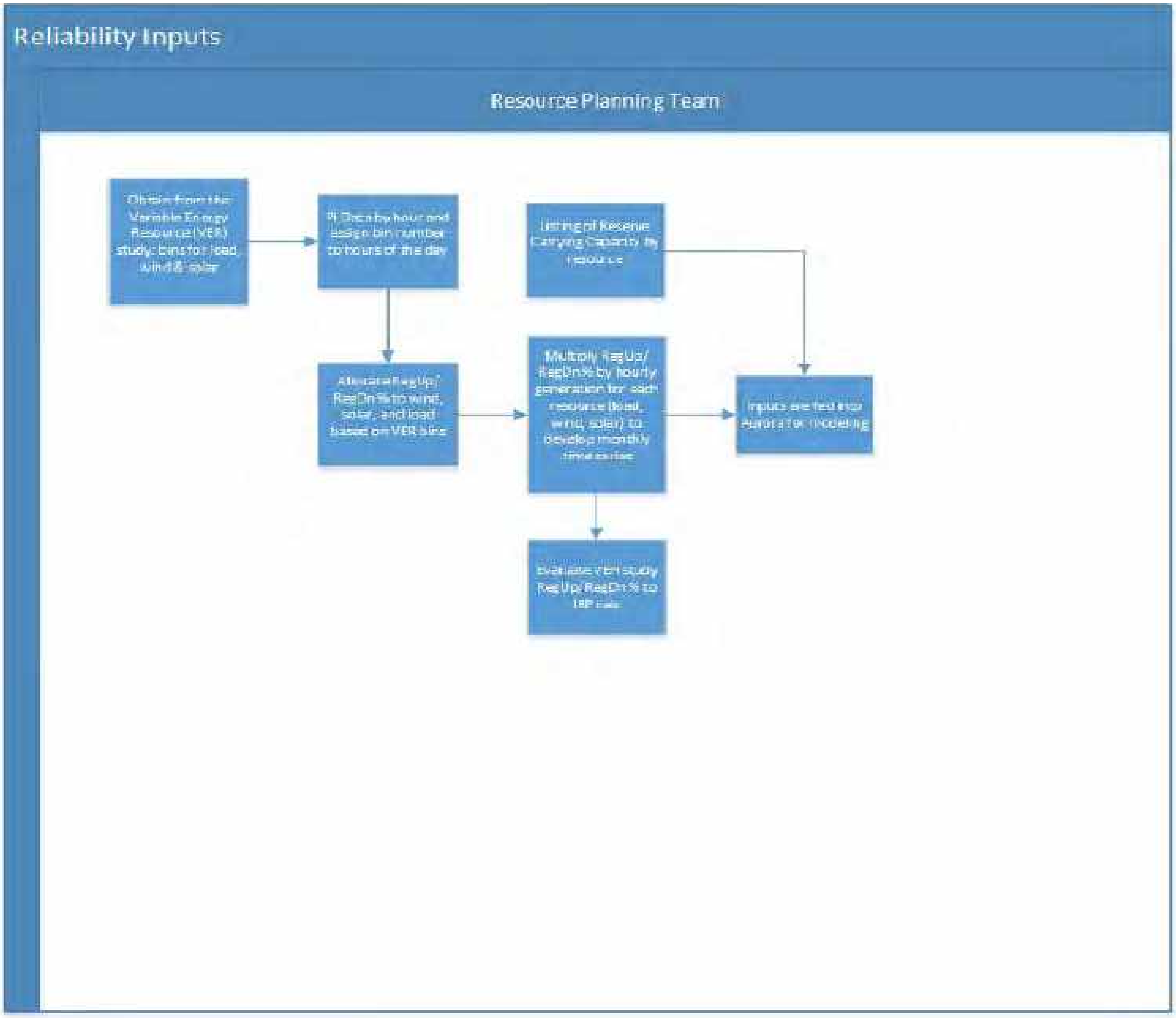

Figure 3.11 Reliability Inputs Process Map

4. AURORA SYSTEM SETTINGS

In Step III of the IRP review, the System Settings Sub-Team performed an assessment of the setup and utilization of the AURORA model for the 2019 IRP. Specifically, this sub-team was assembled to review the model settings that were applied to perform long-term capacity expansion and unit commitment optimization runs in support of the 2019 IRP filing.

4.1 System Settings Review Methodology

The System Settings Sub-Team systematically stepped through AURORA to review all known model system settings. There are three distinct locations within the AURORA model graphical user interface (GUI) where system settings can be adjusted: Project Setup Menu, Simulation Options Menu, and Input Tables. The sub-team created an itemized list of the system settings that reside in each location. The sub-team then reviewed each setting to ensure that they were correctly configured for the 2019 IRP. The discrete settings that were reviewed are shown in Table 4.1 below. It is important to note that not all settings identified in Table 4.1 were utilized in the 2019 IRP. The listed settings are solely a summary of the system settings that the sub-team reviewed for reasonableness in the 2019 IRP.

Table 4.1 AURORA System Settings

Project Setup Menu	Simulation Options Menu	Input Tables
• Active study type • Study period • Study cases and change sets utilized • Output database type and location	• Dispatch settings • Economic base year • Min gen backdown penalty • Resource dispatch margin • Calculate system-wide marginal resources • Inclusion of variable O&M in dispatch • Inclusion of emissions costs in dispatch • Treat ORM input as nominal • Use operating reserves • Use input prices • Use commitment feedback in LDC solve • Use demand net of must-run for hydro shaping • Ignore start costs in commitment • Treat emissions price input as nominal • Use capacity for MW-based commitment input • Use demand in all areas for hydro shaping • Use enhanced storage logic for all storage units • Use bidding logic • Threat resource bidding adder input as nominal • Outage method • Convergent cycle length • Freq duration outages base on elapsed time • Write frequency duration outage debug table • Combine resources segments in reporting • Report averages using online ours only • Include emissions in value reporting • Include fixed O&M in value reporting • Run general risk analysis • Do risk sampling only • Latin hypercube sampling • Number of iterations	• Zonal definition • Resources • Risk definition • Storage setup • Portfolio resource • Portfolio information • New resources • Maintenance schedule • Link • Hydro vectors • Hydro monthly • General information • Fuels • Demand monthly, demand hourly, and demand escalation • Zonal conditions • Areas • Ancillary services

4.2 System Settings Review Results

After reviewing all model settings used in the 2019 IRP, the System Settings Sub-Team concluded that the majority of the model settings used for the 2019 IRP reflected default settings from the vendor, Energy Exemplar. The sub-team determined the system settings and model setup utilized in the 2019 IRP were reasonable and did not recommend any changes. The sub-team concluded, however, that system settings should be reviewed in full prior to each IRP cycle to ensure consistency and accuracy in future modeling.

5. Model Verification and Validation of Key Inputs

In the final step of the review, the IRP Review Team sought to verify and validate the AURORA model outputs to ensure the model produced logical and consistent results. The sub-teams evaluated the reasonableness of the output or performed additional work to validate the data as necessary. For identified adjustments from Steps I through III, sensitivity runs were completed to determine the impact. These sensitivities compared the input data used in the *Amended 2019 IRP* and the associated results to reruns of the model with the adjustments identified by the IRP Review Team. The process to verify and validate the key inputs was unique to each topic and is described in each of the following sub-sections of the report.

5.1 Natural Gas Price Verification and Validation

To validate that the natural gas price forecasts were operating as expected in the model and the outputs were reasonable, the sub-team performed the following review:

Input Verification and Testing

As discussed in Section 3.1.2, the Natural Gas Price Forecast Sub-Team identified that variable transportation costs were not included in Idaho Power's specific natural gas price forecast. To determine the impact of including the natural gas variable transportation costs, a sensitivity analysis was run. The results of the sensitivity run showed an increase in portfolio costs ranging from 0.11 percent to 0.21 percent between the tested portfolios. This impact was deemed too small to impact ultimate resource selection within AURORA. However, the natural gas price forecast used in the *Second Amended 2019 IRP* is inclusive of transportation costs.

Model Validation

1. Peak-Day Comparison – The resource stack dispatched to meet demand through a peak day in the model was compared to the resource stack used to meet peak demand in the summer of 2017. This is a visual comparison to ensure resources are dispatching in the model in a reasonable manner. Natural gas provided a similar proportion of the resource stack in the model during peak hours. However, natural gas peaker plants (SCCTs) are dispatched in the model for a longer duration than actual dispatch indicates. While some variations between the model and actual dispatch are reasonable, as market conditions are expected to vary between the modeled forecasts and historical values, the Review Team conducted a sensitivity to explore this issue further. The sensitivity is described in Section 5.5 (Natural Gas Plant Step IV validation and verification).

2. Dispatch Model Sensitivity – The various natural gas price forecasts (high, mid, low) were compared against each other to determine if AURORA was adopting resources as expected. As a baseline, the review team examined levels of natural gas in a planning gas case. In comparison, the high-cost natural gas case replaces approximately 20 percent of the natural gas dispatched in the planning natural gas case with a combination of market purchases and coal. This result is as expected and showed that the model was dispatching gas resources appropriately based on underlying input costs.

3. Long-Term Capacity Expansion (LTCE) Results – The resources selected to add or reduce capacity in each portfolio by the LTCE model can be compared across natural gas forecast assumptions to determine if the results match expectations. This information is contained in the *Amended 2019 IRP* as Figure 8.3 for non-B2H portfolios and Figure 8.4 for B2H portfolios. In these figures, the first four (left-most) resource stacks shown were developed under a planning natural gas scenario. The next four were developed with the mid-natural gas forecast. And the last four (right-most) resource stacks were developed under a high-cost natural gas forecast. In both figures, equal or fewer natural gas resources were selected by the model in the planning gas scenarios than the resource stacks built under high-gas conditions when comparing the same carbon conditions. The reduction in natural gas selection is most obvious when comparing planning gas and generational/high carbon cases to the high gas and generational/high carbon cases. As expected, natural gas is selected considerably less under high gas price and generational and high carbon cost conditions.

Natural Gas Price Forecast Sub-Team Results of Step IV Review

An evaluation of the three checks performed on the natural gas pricing forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The natural gas price forecasts.
- The treatment of the natural gas price forecasts within the AURORA model.
- The outputs of the model.

5.2 Hydrology and Stream Flow Forecast Verification and Validation

To validate the hydrology and stream flow forecast was operating as expected in the model and the related constraints in AURORA were reasonable, the sub-team selected the most significant set of hydroelectric plants, the Hells Canyon Complex (HCC), and performed the following review:

1. HCC Hourly Ramp Rate – The AURORA modeling results for the 2019 year and base case run were aggregated into a single HCC resource (Hells Canyon + Oxbow + Brownlee). The hourly ramp rate for the HCC was plotted in a histogram. Based on historical observed ramp rates from 2004-2019, the HCC hourly ramp rate falls within 150 MW/hour up and down approximately 95 percent of the time. In AURORA, ramping of the HCC fell within 150 MW/hour approximately 80 percent of the time. While the model results did not exactly match the historical distribution, the general shape of the distribution is similar, and some deviation is expected in a model versus actual operations comparison. The sub-team also gained confidence observing the overall monthly energy budget is honored in the model. Accordingly, the team determined the hourly ramp rate results in the model output were reasonable.

2. HCC Pmax/Pave and Pmin/Pave ratios – Using AURORA modeling results for HCC, the ratio of the hourly daily maximum HCC generation (Pmax) was normalized by

the daily average generation (Pave). The same calculation was performed for the minimum generation (Pmin) normalized by Pave. The distribution of Pmax/Pave and Pmin/Pave were compared to the observed distribution of these ratios for the 2004-2019 historical period. This check was performed to gain an understanding of how much the AURORA model ramps the HCC up and down, compared to how much the company ramps the HCC in observed operations. The results generally showed that AURORA ramps the HCC over a wider range than in actual practice, with larger Pmax/Pave ratios generally occurring in all months except April. While not as pronounced, Pmin/Pave ratios generally were lower than the observed period, with April again being more constrained in AURORA than the historical data shows. Similar to the complex ramp rates, the sub-team concluded that it is more important that the model honor the monthly energy budget than exactly replicate ratios of Pmax/Pave and Pmin/Pave. Accordingly, the team determined the Pmax/Pave and Pmin/Pave ratio results in the model output were reasonable.

3. Hells Canyon Dam Ramp Rate – The AURORA modeling results for Hells Canyon Dam were evaluated to determine if the hourly ramp rate was comparable to how Hells Canyon Dam is operated in practice. Typically speaking, an hourly step of approximately 30 to 50 MW/hour corresponds to the maximum ramping capability at Hells Canyon Dam to meet the license requirement of changing river stage on the Snake River at Johnson Bar no more than 1 foot/hour. The AURORA results showed that Hells Canyon Dam is commonly ramped more than 50 MW/hour, which would likely lead to a compliance event if done in practice. Even though Hells Canyon is ramped more than 50 MW/hour, the results from the HCC as a whole (validation Steps I and II above) demonstrated that the energy produced for the HCC as a whole was reasonable. While a revision was not recommended for the 2019 IRP, the sub-team agreed that the issue warrants further consideration in future IRPs. Accordingly, the team discussed and determined the AURORA modeling results were reasonable.

4. Hells Canyon Dam Daily Flow Fluctuation – The AURORA modeling results for Hells Canyon Dam were evaluated to determine if the daily flow fluctuation was comparable to the way in which Hells Canyon Dam is operated in practice. While not currently a license requirement, but rather an anticipated license requirement, the company attempts to limit daily flow fluctuations below Hells Canyon Dam to 10,000 cubic feet per second (cfs) from June 1 through September 30. From October 1 through May 31, with the exception of the fall Chinook flat flow period, the company tries to limit daily flow fluctuations to 16,000 cfs below Hells Canyon Dam. The flow fluctuations were converted to a range in MW, using the Hells Canyon Dam k-factor. A fluctuation of 10,000 cfs corresponds to a daily MW fluctuation of 150 MW, and a fluctuation of 16,000 cfs corresponds to a daily MW fluctuation of 240 MW. The AURORA modeling results showed that these limits are generally honored October through April. May through September saw larger fluctuations than would likely occur based on the flow range guidance. As limits are generally honored and the flow fluctuations were as expected, the sub-team determined the results were reasonable.

5. Hydroelectric Operation – As an additional validation step, the sub-team validated hydroelectric operation in aggregate within the model. The team reviewed a graphical

representation of July 2019 forecasted peak day generation as modeled in AURORA to July 2017 actual peak day generation, noting forecast hydro generation for the peak day in AURORA behaved in a similar way to hydro generation on the historical peak day. The hydro generation is forecast lower in the morning hours and ramps up later in the day, as expected. The amount of hydro generation modeled during the peak hours closely matches the actual hydro generation during peak hours in 2017. The similarities between modeled results and actual historical data indicate that hydro generation is being modeled reasonably within AURORA.

Hydrology and Stream Flow Forecast Sub-Team Results of Step IV Review

An evaluation of the checks performed on the Hydrology, Stream Flow forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The Hydrology and Stream Flow forecasts.
- The treatment of the Hydrology and Stream Flow forecasts within the AURORA model.
- The outputs of the model.

5.3 Load Forecast Verification and Validation

To verify and validate the load forecast was operating as expected in the model, the sub-team anticipated a direct relationship between the load forecast input, as reviewed in Section 3.3.1 (Review Step I), and the output of the AURORA model. In Section 3.3.2 (Review Step II). The sub-team verified the hourly load forecast provided by the Load Forecasting team matched the load forecast included in all portfolios.

Load Forecast Sub-Team Results of Step IV Review

An evaluation of the checks performed on the hourly load forecast and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The hourly load forecast.
- The treatment of the hourly load forecast within the AURORA model.
- The outputs of the model.

5.4 Coal Plant Verification and Validation

To validate the operating characteristics, cost inputs, and coal price forecasts were operating as expected in the AURORA model and the outputs were reasonable, the following steps were performed:

Model Validation

1. Bridger Unit Generation – The Bridger unit generation in each year for Portfolios P2(3), P14(3), and P16(4) was compared to the minimum generation capabilities and maximum

generation capabilities per generator ratings in AURORA.[2] The annual modeled generation was determined reasonable if it fell between the minimum and maximum capability levels in a given year. Based on review of all three portfolios, all modeled generation outputs fell within these limits and the annual Bridger generation level was determined to be reasonable.

2. Bridger Fuel Expense – The Bridger unit fuel expense for each year for Portfolios P2(3), P14(3), and P16(4) was compared to the manual calculation of fuel expense based on fuel forecast inputs and the average heat rate of the plant. Reviewing over the 20-year period, if the annual Bridger unit fuel expense for a year was higher than the fuel expense calculated using the average plant heat rate more than 50 percent of the time, then the fuel expense is deemed intuitively reasonable. This threshold is based on the theory that the Bridger plant would be running at minimums during certain times, resulting in a lower efficiency, which, in turn, increases the fuel expense per MWh. Review of all three portfolios showed that modeled fuel expense fell within these limits and the annual Bridger fuel expense was deemed intuitively reasonable.
3. Bridger Fixed Cost Expense – The AURORA Bridger unit fixed cost for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of fixed expense based on fixed cost per MW-week inputs and rated capacities. AURORA's fixed costs and common facility costs in the portfolios should reconcile to the manual calculation of fixed costs. Review of all three portfolios showed that modeled fixed costs reconcile to the fixed cost inputs.
4. Bridger Variable O&M – The Bridger variable O&M expenses for each year in P2(3), P14(3), and P16(4) were compared to a manual calculation of variable O&M expense based on the updated O&M per MWh rates provided by Finance.
5. Valmy Fuel Expense – The Valmy unit fuel expense entered into AURORA for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of fuel expense based on fuel forecast inputs and the average unit heat rate. If the annual Valmy Unit 2 fuel expense in the model is higher than the fuel expense calculated using the average plant heat rate more than 50 percent of the time, then the fuel expense is deemed intuitively reasonable. This is based on the theory that if the Valmy plant is running at minimums at times, the result is a lower efficiency, which, in turn, increases the fuel expense per MWh. Review of all three portfolios found all modeled fuel expenses met this constraint.
6. Valmy Variable O&M – The AURORA Valmy variable O&M for each year in P2(3), P14(3), and P16(4) was compared to a manual calculation of variable O&M expense based on actual O&M per MWh rates.

[2] Section 6.2 provides a detailed discussion of why these portfolios were selected as the basis for additional analysis.

Coal Units Sub-Team Results of Step IV Review

The sub-team determined that coal unit operations were modeled as expected in AURORA. Updates were made to the Bridger fixed, Bridger common facility costs, and variable O&M costs, and, through validation, were included in the portfolio cost re-runs as expected.

5.5 Natural Gas Plant Verification and Validation

To validate the operating characteristics of the natural gas plants were functioning as expected in the model and to address the inconsistencies identified in Sections 3.5.1 and 3.5.2 (Review Steps I and II) related to start-up costs and the ramp rate for Langley Gulch, the following steps were performed:

Input and Setting Verification

1. Variable O&M Rate for Langley – It was noted during the Step IV review of the coal inputs that AURORA interprets the variable O&M input rate as a nominal 2012 amount and then escalates the rate to a 2019 nominal amount. This was also determined to be the case for the variable O&M input rate for Langley Gulch. The sub-team determined the variable O&M rate had already been input in AURORA at a 2019 nominal rate of $2.67 and would need to be deflated to account for the automatic escalation performed in AURORA. The 2019 nominal rate of $2.67 was deflated to a 2012 nominal rate of $2.37. This correction did not affect the natural gas peaking plant units, as the variable O&M expense had been incorporated into the start-up costs.

2. Review Gas plant settings in AURORA – The gas plant settings were reviewed for reasonableness by the company's subject matter experts. The following settings were discussed and deemed reasonable: Heat rate, capacity, forced outage rate, heat rate at minimum, minimum capacity, min up time, and min down time. The sub-team identified two model settings that were not used: 1) Fixed O&M and 2) Non-Cycling. Fixed O&M was not used in the model because the costs are the same among all alternatives and are therefore unnecessary. The Non-Cycling setting was not used as it is not a plant characteristic, but rather a 5 percent premium applied to the dispatch price to ensure that the unit is being dispatched at a profit.

Model Validation

1. Peaking Plants– A sensitivity analysis was performed that changed the maintenance calculation of two peakers—Bennett Mountain and Danskin 1—from a variable O&M charge (which spreads maintenance costs across MWh) to a cost per start. The small peakers (Danskin 2 and 3) were also included in a separate start cost sensitivity analysis. The sensitivity analysis showed that the use of a variable O&M charge in the model resulted in understatement of the total maintenance costs, while the use of a cost per start captured the full cost of plant maintenance. Further, the use of a cost per start showed a decrease in the number of starts without a corresponding decrease in total energy. To further validate the results, the sub-team compared the results of the AURORA output to actual 2019 maintenance costs. The variance between the modeled maintenance costs and 2019 actuals was within 3 percent, a variance the sub-team considered reasonable. The

sensitivity analysis showed minimal change in total portfolio NPV cost compared to the amended 2019 IRP (ranging from an approximate 0.8 percent increase in NPV for P2(3) up to about a 1.2 percent increase for P16-4). For the Danskin 2 and 3 start-up cost sensitivity, an increased start-up cost for these two units did not materially change the portfolio NPV.

2. Ramp Rate for Langley – The ramp rate for Langley was set at 100 percent, meaning that the plant can ramp from 0 to full capacity in one hour. The actual ramp rate is less than 100 percent and varies based on starting conditions. This modeling assumption was discussed with the company's subject matter experts, and a sensitivity was performed in AURORA to assess the impact of different ramp rates on the total portfolio NPV costs. Compared to the *Amended 2019 IRP* modeling with a 100 percent ramp rate, the following reduced ramp rates were used to determine impact on portfolio cost in NPV: A 23 percent ramp rate increased the NPV by 0.05 percent; a 50 percent ramp rate increased the NPV by 0.02 percent; and a 60 percent ramp rate increased the NPV by 0.05 percent. The results show that reduced ramp rates have only a minimal increase to the portfolio NPV and have an immaterial impact on the overall portfolio outcomes. The sub-team determined that a 60 percent ramp rate would better reflect actual operations and the plant setting was adjusted accordingly.

3. Review of Key AURORA Output – Key AURORA outputs for Langley Gulch, listed below, were reviewed by the company's subject matter experts and deemed reasonable based on comparison to historic actuals:

    a. Average Annual MWh Output

    b. Average Minimum Capacity MW

    c. Peak Capacity MW

    d. Total Annual MWh Output

    e. Annual Capacity Factor

    f. Total Hours Run

    g. Average Forced Outage MW

Natural Gas Plant Sub-Team Results of Step IV Review

The sub-team concluded that AURORA modeled natural gas plant operations as expected. The sub-team also reviewed the system settings related to natural gas plants and they were deemed reasonable. Adjustments were made to the peaker plants' start-up costs and variable O&M rates. Each adjustment was put through a sensitivity analysis, the results of which are discussed in Section 6.3. Additionally, these natural gas plant adjustments were evaluated in aggregate through portfolio analysis and the results are also discussed in Section 6.3.

5.6 CSPP and PURPA Verification and Validation

To verify and validate that the CSPP and PURPA forecast was operating as expected in the model, the sub-team assumed a direct relationship between the CSPP/PURPA generation forecast input (as reviewed in Section 3.6.1) and the output of the AURORA model. The sub-team verified that the CSPP/PURPA generation included in all portfolios, totaling 57,869,550.55 MWh over the 20-year planning period, matched the forecast inputs.

CSPP Sub-Team Results of Step IV Review

An evaluation of the checks performed on the CSPP/PURPA forecasts and model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The CSPP/PURPA forecasts.
- Treatment of the CSPP/PURPA forecasts within the AURORA model.
- The outputs of the model.

5.7 Demand Response and Energy Efficiency Verification and Validation

To validate that Demand Response (DR) and Energy Efficiency (EE) were operating as expected in the model, the sub-team performed the following review for each:

Demand Response

Legacy and expanded DR programs were validated for capacity, shaping, and cost as outlined in Section 3.7.2 (Review Step II). Further validation was conducted to ensure that AURORA was treating DR consistent with the way Idaho Power's DR operates:

1. DR Adoption – The sub-team compared AURORA logic to expectations by evaluating a zero-carbon-cost portfolio to a high-carbon-cost portfolio. The team agreed that it would expect AURORA to elect for more DR in the high-carbon-cost portfolio. Evaluation of the test portfolios—Portfolio 1 (planning gas, no carbon) and Portfolio 12 (high gas, high carbon)—confirmed the team's hypothesis: Portfolio 1 (zero carbon cost) showed no DR expansion while in Portfolio 12 (high carbon cost) expanded Demand Response programs by 40 MW over the planning period.
2. DR Dispatch Function – While performing DR verification and validation, dispatch settings for DR were reviewed. It was identified that future DR was only dispatched in resource deficit situations. The team determined it would be more appropriate and consistent with DR program operations to set these programs to dispatch during summer peak load hours. Testing of this change showed greater amounts of dispatched DR under the peak load setting.
3. DR Cost of Capital – The sub-team reviewed the fixed costs associated with DR programs within the framework of future supply-side resources. This review revealed that the annualized cost of capital only applied to the three peak summer months (June, July, and Aug) when DR programs are dispatched. Upon discussion with subject matter

experts, the sub-team determined that the annualized cost of capital for those programs should be spread across the entire year. Sensitivity analysis revealed an impact of approximately $0.4 million per year for each 5 MW tranche of DR. As a result, the sub-team determined the cost of capital for DR should be spread throughout a 12-month period versus just summer peak months.

Energy Efficiency

To verify and validate that EE was operating as expected in the model, the sub-team confirmed that the levels of economic achievable EE included in the load forecast input matched the EE bundles identified by AEG, as reviewed in Section 3.7.1 (Review Step I) and the output of the AURORA model.

DR-EE Sub-Team Results of Step IV Review

An evaluation of the checks performed on DR and EE, as well as model outputs, resulted in the following conclusions:

- DR is being adopted as expected in AURORA.
- DR should be dispatched to offset peak load during peak summer months when DR programs are operating.
- The cost of capital for DR should be spread across the year rather than just in summer peak months.
- The inclusion of economic achievable potential EE is included in the hourly load forecast as expected.
- The treatment of the potential energy efficiency included in the hourly load forecast within the AURORA model was reasonable.

5.8 Transmission Verification and Validation

Because there is not an AURORA output produced as a result of the transmission assumptions, the verification and validation related to transmission focused on the sensitivity analysis recommended in Section 3.8.1 (Review Step I) and Section 3.8.2 (Review Step II), which resulted in adjustments to loss fractions, wheeling rates, and capacity as shown in Table 5.1.

Table 5.1 Updated Transmission Assumptions

Link	Losses fraction	Wheeling changes	Capacity (MW)
IPC B2H In	0.0445 to 0.019		
PAC B2H Import		\$2.83 to \$3.67	
IPC B2H export			+85
LGBP out	0.066 to 0.036		
LOLO in	0.0445 to 0.03		+53 BDMN retirement +200 (non-summer months) in 6/2026 BPA CF
LOLO out	0.0445 to 0.036		
JBWEST W-E IPC	0.0445 to 0.036		-350 (600 to 250)
BWEST E-W PAC		\$3.67 to \$3.58	
IPC-PAC (SMLK)		\$3.58 to \$3.67	
Path18 in	0.033 to 0.04	\$3.67 to \$4.72	
Path18 out IPC	0.0445 to 0.036		
Path18 out PACE	0.033 to 0.0445		

Transmission Sub-Team Results of Step IV Review

The inputs identified in Table 5.1 were updated in the model and the company re-ran four portfolios to validate the impact of the adjustments. The results of the new portfolios were compared to select portfolios in the *Amended 2019 IRP* and revealed that the largest difference was a 0.26 percent reduction in cost for the Preferred Portfolio. As a result of this minimal impact, the sub-team determined that the transmission assumption adjustments had a minimal impact on cost and were ultimately immaterial to portfolio selection.

5.9 Boardman to Hemingway Inputs Verification and Validation

To validate the B2H financial assumptions, the sub-team reviewed the addition of B2H costs to portfolios in which B2H was an identified resource. The costs for B2H were not entered into AURORA but were manually added to the portfolio costs for B2H-specific portfolios after the portfolio costs were exported out of AURORA. The sub-team validated that the costs were included as expected in Section 3.9.2 (Review Step II).

Boardman to Hemingway Inputs Sub-Team Results of Step IV Review

The sub-team identified the B2H net present value costs were appropriately added to the AURORA modeled costs, as expected. Updates were made to the B2H estimated levelized capacity cost.

5.10 Financial Inputs and Future Supply-Side Resource Verification and Validation

To verify and validate the financial assumptions used to calculate the levelized costs of supply-side resources and to address the inconsistencies identified in Section 3.10.1 and 3.10.2 (Review Steps I and II) related to property tax rates and annual insurance premiums, the sub-team performed the following steps:

1. Property Tax Rate – The team identified several financial inputs that were updated based on the information gathered in the review meetings as noted in Sections 3.10.1 and 3.10.2 (Review Steps I and II). The property tax rate was updated from 0.29 percent to 0.49 percent and annual insurance premiums were changed from 0.31 percent to 0.03 percent. The PWorth model was updated for each new supply-side resource to reflect the change in cost assumptions.

2. Secondary Review of Financial Assumption System Settings – The sub-team conducted a secondary check of financial assumptions in the LTCE model decision making and found them reasonable and consistent with the Step III review.

3. Future Supply-Side Resource Adoption – The sub-team compared AURORA logic to expectations by evaluating a zero-carbon-cost portfolio to a high-carbon-cost portfolio. The team agreed that it would expect AURORA to select coal exits earlier in the high-carbon-cost portfolio. Evaluation of the test portfolios—Portfolio 1 (planning gas, no carbon) and Portfolio 12 (high gas, high carbon)—confirmed the team's hypothesis: Portfolio 1 (zero carbon cost) removed 318 MW of coal while Portfolio 12 (high carbon cost) removed 849 MW of coal. This indicates that the logic within the AURORA LTCE performs according to expectations.

Financial Inputs and Future Supply-Side Resources Sub-Team Results of Step IV Review

An evaluation of the checks performed on the financial inputs and future supply-side resource outputs indicate the following were reasonable within the 2019 IRP analysis:

- Debt to Equity composition.
- Weighted Average Cost of Capital.
- General Escalation Factor (as measured by CPI).
- General Future Resource specifications as outlined (e.g., economic life, heat rate, overnight capital).

- Annual Escalation and de-escalation rates associated with future resources.

An evaluation of the checks performed on the financial inputs and future supply-side resource outputs indicate the following were subject to change within the 2019 IRP analysis:

- Property tax rate used in the PWorth model of future supply-side resources.
- Insurance premium rate used in the PWorth model of future supply-side resources.

5.11 Reliability Inputs Verification and Validation

To address the inconsistencies identified in Section 3.11.1 (Review Step I) related to RegDn percentages and the reserve carrying capacity of Valmy Units 1 and 2, and to validate that the other reliability inputs were operating as expected in the model, the following steps were performed:

Input Verification

1. LoadDown, SolarDown – To address the inconsistency identified in Section 3.11.1 (Review Step I) related to the RegDn percentages, the team determined a sensitivity analysis should be performed to understand the issue's impact. The team concluded the following:
    - The updates to LoadDown and SolarDown were immaterial to resource selection and portfolio cost.
    - The practical difference in the amount of reserve shortfalls between the *Amended 2019 IRP* and the updated LoadDown/SolarDown results is insignificant at 0.00001029 percent and 0.00010882 percent of total MWh over the 20-year planning horizon for RegDn and Spin, respectively.
    - Based on review of the sensitivity analysis, the team determined the reliability inputs included in the *Amended 2019 IRP* are reasonable.
2. Removal of Valmy's Ability to Provide Reserve Carrying Capacity – To address the inconsistency identified in Section 3.11.1 (Review Step I) related to the reserve carrying capacity of Valmy, the team determined a sensitivity analysis should be performed to assess the impact. Results of the analysis were as follows:
    - Prior to making the adjustment, Valmy Units 1 & 2 were providing almost no reserves (rounded to 0 percent of total reserves). Therefore, the removal of these units' ability to provide reserve carrying capacity did not make a material impact.
    - The practical difference in the amount of reserve shortfalls between the amount in the *Amended 2019 IRP* and the sensitivity analysis results is insignificant at 0.00085853 percent of total MWh over the 20-year planning horizon for RegUp reserve violations. The difference is even smaller for RegDn and Spin Reserve violations.

Model Validation

1. Contingency Reserves – These reserves are set at 6 percent (3 percent of load + 3 percent of generation) in the model. Historical data for 2019 showed 6 percent on average held as contingency reserves across the year. The AURORA output for 2019 also showed 6 percent contingency reserves on average for the year. As a result, the review sub-team determined that the reserves used in the model are reasonable compared to the historical reserves.

2. AURORA Max Reserves by Unit – Idaho Power's Load Serving Operations provided the max reserve capacity that each unit could potentially provide to the system. This was then compared to the max amount of reserves provided by each unit in AURORA for 2019. While on an hourly basis AURORA produced max reserves for some units above their stated max reserve capacity, the parameters defined within the model to characterize each unit's ability to provide reserve capacity up to a max were examined and found reasonable.

3. Reserve Shortfall – This check provided an assessment of how AURORA met reserves given a specific portfolio buildout. In reviewing the AURORA output for P16(4), in the 7-year action window, there was a projected reserve shortfall of just 54 MWh out of 119,000,000 MWh of total load. This assessment showed that AURORA is adequately meeting reserve requirements.

4. Loss of Load – During the 2019 IRP, there was an analysis performed on Loss of Load Probability for the four portfolios selected for manual optimization (2, 4, 14, and 16) to ensure that AURORA was providing adequate system reliability. The analysis found that each of the four portfolios provided adequate system reliability (LOLE <=.01 hours/year), which is well within the threshold commonly used in the industry of one day every ten years.

Reliability Inputs Sub-Team Results of Step IV Review

An evaluation of the checks performed on the reliability inputs and AURORA model outputs indicate the following were reasonable within the 2019 IRP analysis:

- The reliability inputs.
- The treatment of the reliability inputs within the AURORA model.
- The outputs of the AURORA model.

6. IRP Review Results

6.1 Review Results Summary

The company conducted a comprehensive review process to deconstruct and examine all aspects of the 2019 IRP cycle from model inputs to model outputs, as discussed in prior sections of the report. While most inputs, system settings, and outputs were determined to be reasonable, the sub-teams collectively identified a few recommended adjustments. These adjustments are detailed above in Section 3 on inputs (review steps I and II), Section 4 on system settings (review step III), and Section 5 on model verification and validation (review step IV). The sections below provide a methodology by which the impact of adjustments can be understood, as well as a compiled list of all adjustments identified across the four steps of the review process and their relative impact on portfolio development.

6.2 Evaluation Methodology

To test the impact of identified input and system setting adjustments, a group of portfolios was selected for re-evaluation with refreshed information from this review process. The model was run for individual adjustments and then also with all adjustments collectively.

The adjustments were made to the following portfolios from the *Amended 2019 IRP*:

- Portfolio 16(4) – The Preferred Portfolio was included to determine the relative impact to the *Amended 2019 IRP* preferred plan.
- Portfolio 14(3) – Based on the number of identified coal input related changes, this portfolio was selected because it has later coal exits and a relatively low NPV compared to other portfolios with similar Bridger exit dates.
- Portfolio 2(3) – This was the best-performing portfolio without B2H in the *Amended 2019 IRP* and was selected to gauge the impact of the changes to the relative value of the project.

These portfolios were the most appropriate for impact testing because of their underlying characteristics and potential for change.

6.3 Impacts of Identified Adjustments

The results of the various sensitivity runs are shown in Table 6.1 and described below.

1. Natural Gas Transport Costs
    a. **Identified Changes** – The sub-team determined that the variable transport costs were inadvertently not included in the model.
    b. **Steps Taken** – These costs were added to the model.
    c. **Results** – The adjustment increased the cost of the Preferred Portfolio by 0.11 percent. This relatively minor impact varied between the tested portfolios with a ranged increase from 0.11 percent to 0.21 percent.
2. New Resource Financial Assumptions
    a. **Identified Changes** – The sub-team determined that the annual property tax rate and annual insurance premium needed adjustment. These values impact the cost of new resources added to Idaho Power's generation stack, including the B2H project.

b. **Steps Taken** – Financial assumptions were updated, and the financial analysis was performed again. The results of the financial analysis were then updated in the model.

c. **Results** – The financial adjustments decreased the cost of the Preferred Portfolio by 0.12 percent. This relatively minor impact was consistent among the tested portfolios with a ranged decrease from 0.04 percent to 0.12 percent.

3. Bridger Units 3 and 4 Fixed Cost Rates (Coal Reference)

   a. **Identified Changes** – The fixed cost rates for Bridger Unit 4 were inadvertently referencing the table of fixed costs for Bridger Unit 3 within AURORA.

   b. **Steps Taken** – The table reference within the model was corrected.

   c. **Results** – The Bridger coal unit reference adjustment increased the cost of the Preferred Portfolio by 0.04 percent. This relatively minor impact was consistent among the tested portfolios with a ranged increase in portfolio cost from 0.04 percent to 0.11 percent.

4. Regulation Reserves Adjustment

   a. **Identified Changes** – The solar and wind allocation factors for downward regulation referenced the upward allocation factors. Additionally, Valmy Unit 2 was modeled with the ability to provide regulation reserves, but the unit cannot provide regulation reserves.

   b. **Steps Taken** – The solar and wind references were redirected to the downward regulation allocation factors in the input spreadsheet and the regulation rules were updated in the model, while Valmy was adjusted within the model to not provide reserves.

   c. **Results** – The regulation reserve adjustments—including solar and wind changes, as well as Valmy—increased the cost of the Preferred Portfolio by 0.003 percent (rounded to 0.00 percent in Table 6.1). This relatively minor impact varied among the tested portfolios with a ranged increase between 0.003 percent and 0.10 percent.

5. Transmission Characteristics

   a. **Identified Changes** – The losses, wheeling rates, and capacities applied to some transmission lines required adjustment. Additionally, transmission capacity after the Boardman unit exit was understated.

   b. **Steps Taken** – The loss and wheeling rates were updated in the model. The transmission capacity adjustment was also implemented.

   c. **Results** – The losses, wheeling rates, and capacity adjustments decreased the cost of the Preferred Portfolio by 0.26 percent. This relatively minor impact varied among the tested portfolios from a decrease of 0.26 percent to an increase of 0.01 percent.

6. Bridger Variable O&M

    a. **Identified Changes** –The variable O&M costs associated with the Bridger units included the total variable O&M costs but should have been modeled as one-third of the costs, as contractually agreed to reflect the fractional ownership between Idaho Power and PacifiCorp.

    b. **Steps Taken** – The share of Bridger O&M costs was adjusted in the P-Worth model and the resulting adjustments were made to the AURORA model.

    c. **Results** – The Bridger variable O&M adjustment decreased the cost of the Preferred Portfolio by 0.42 percent. The impact among the tested portfolios ranged from a decrease of 0.42 percent to 0.48 percent.

7. Natural Gas Peaker Plant Startup Costs

    a. **Identified Changes** – The maintenance costs associated with natural gas peaker plants were captured only as a variable cost applied directly to the runtime of the unit. No startup costs were included, which resulted in more frequent dispatch of the peaker plants and for shorter durations than expected.

    b. **Steps Taken** – The sub-team utilized historical and projected maintenance information for the peaker plants to determine an appropriate start-up cost. This cost was applied in the model. The gas dispatch from the model was then reviewed to confirm that the adjustment reduced the number of peaker plant starts and lengthened individual runtime durations as expected.

    c. **Results** – The adjustment to the startup costs of the peaker plants resulted in the largest impact to the results of all the adjustments across the tested portfolios. The Preferred Portfolio increased by 0.93 percent, with increases among the tested portfolios ranging from 0.79 percent to 1.07 percent.

8. Bridger Fixed Costs

    a. **Identified Changes** – While reviewing financial assumptions throughout the model, it was discovered that some of the financial assumptions for the Bridger coal units did not match the financial assumptions used throughout the rest of the model.

    b. **Steps Taken** – The financial assumptions were adjusted in the PWorth model and the resulting adjustments were made to the model.

    c. **Results** – The Bridger fixed cost adjustments increased the cost of the Preferred Portfolio by 0.14 percent. This relatively minor impact varied between the tested portfolios with a ranged increase from 0.14 percent to 0.26 percent.

9. Bridger Common Facility Costs

    a. **Identified Changes** – While reviewing financial assumptions throughout the model, it was discovered that some of the Bridger common facility costs were truncated as Bridger units were retired early.

    b. **Steps Taken** – The truncated Bridger common facility costs were added back to the Bridger fixed costs, which are added to the total portfolio costs for the collective review results for all cases.

    c. **Results** – The Bridger common facility cost adjustments increased the cost of the Preferred Portfolio by 0.51 percent. This impact varied between the tested portfolios with a ranged increase from 0.51 percent to 0.59 percent.

Assessed individually, the identified modeling adjustments showed limited impact to total portfolio costs. Collectively, the adjustments also had minimal impact on portfolio costs. Further, the collective adjustments did not change the ranking of the identified Preferred Portfolio against the best-performing non-B2H portfolio and the best-performing portfolio with later Bridger exit timing.

Table 6.1 Sensitivity Analysis Results

P16(4)	Amended 2019 IRP (Jan 2020)		Supplement Filing (May 2020)		Collective Review Results		% Difference		
	P16(4) Base	Rank	P16(4) Base	Rank	All Cases	Rank	B/A	C/A	C/B
Aurora	$ 5,885,900		$ 5,885,900		$ 5,963,335				
Bridger Fixed			$ 130,565		$ 162,104				
B2H	$ 110,578		$ 110,578		$ 107,818				
Valmy					$ (5,035)				
Total	**$ 5,996,478**	**1**	**$ 6,127,043**	**1**	**$ 6,228,222**	**1**	**2.18%**	**3.86%**	**1.65%**
Difference									
Percentage									
P14(3)									
($ x 1000)	P14(3) Base	Rank	P14(3) Base	Rank	All Cases	Rank	B/A	C/A	C/B
Aurora	$ 5,957,723		$ 5,957,723		$ 6,041,206				
Bridger Fixed			$ 64,162		$ 104,655				
B2H	$ 110,578		$ 110,578		$ 107,818				
Valmy					$ (5,035)				
Total	**$ 6,068,301**	**2**	**$ 6,132,463**	**2**	**$ 6,248,644**	**2**	**1.06%**	**2.97%**	**1.89%**
Difference									
Percentage									
P2(3)									
($ x 1000)	P2(3) Base	Rank	P2(3) Base	Rank	All Cases	Rank	B/A	C/A	C/B
Aurora	$ 6,143,832		$ 6,143,832		$ 6,213,013				
Bridger Fixed			$ 64,162		$ 104,655				
B2H	$ -		$ -		$ -				
Valmy					$ (5,035)				
Total	**$ 6,143,832**	**3**	**$ 6,207,994**	**3**	**$ 6,312,633**	**3**	**1.04%**	**2.75%**	**1.69%**
Difference									
Percentage									

P16(4)	Aurora Sensitivities								
	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 5,897,604	$ 5,883,283	$ 5,893,225	$ 5,891,146	$ 5,877,895	$ 5,865,135	$ 5,947,835	$ 5,899,292	$ 5,963,335
Bridger Fixed	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 130,565	$ 162,104
B2H	$ 110,578	$ 110,578	$ 110,578	$ 110,578	$ 107,818	$ 110,578	$ 110,578	$ 110,578	$ 107,818
Valmy	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 6,131,712**	**$ 6,119,391**	**$ 6,129,333**	**$ 6,127,253**	**$ 6,111,243**	**$ 6,101,243**	**$ 6,183,963**	**$ 6,135,399**	**$ 6,228,222**
Difference	$ 6,670	$ (7,652)	$ 2,290	$ 211	$ (15,800)	$ (25,800)	$ 56,920	$ 8,357	$ 101,180
Percentage	0.11%	-0.12%	0.04%	0.00%	-0.26%	-0.42%	0.93%	0.14%	1.65%
P14(3)									
($ x 1000)	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 5,971,719	$ 5,956,583	$ 5,965,994	$ 5,965,004	$ 5,952,606	$ 5,932,548	$ 6,024,703	$ 5,974,723	$ 6,041,206
Bridger Fixed	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 104,655
B2H	$ 110,578	$ 110,578	$ 110,578	$ 110,578	$ 107,818	$ 110,578	$ 110,578	$ 110,578	$ 107,818
Valmy	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 6,145,116**	**$ 6,129,980**	**$ 6,139,392**	**$ 6,138,402**	**$ 6,123,244**	**$ 6,105,946**	**$ 6,198,101**	**$ 6,148,126**	**$ 6,248,644**
Difference	$ 12,654	$ (2,482)	$ 6,929	$ 5,939	$ (9,219)	$ (26,517)	$ 65,638	$ 15,663	$ 116,181
Percentage	0.21%	-0.04%	0.11%	0.10%	-0.15%	-0.43%	1.07%	0.26%	1.89%
P2(3)									
($ x 1000)	NG Transport	New Resource Fixed Cost	Coal Reference	RegRules Adj with Valmy	Transmission Updates	Bridger Variable O&M	NG Peaker	Bridger Fixed	All Cases
Aurora	$ 6,156,103	$ 6,139,230	$ 6,151,462	$ 6,145,982	$ 6,146,004	$ 6,115,344	$ 6,193,934	$ 6,160,196	$ 6,213,013
Bridger Fixed	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 67,855	$ 104,655
B2H	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Valmy	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)	$ (5,035)
Total	**$ 6,218,923**	**$ 6,202,050**	**$ 6,214,282**	**$ 6,208,802**	**$ 6,208,824**	**$ 6,178,164**	**$ 6,256,754**	**$ 6,223,016**	**$ 6,312,633**
Difference	$ 13,929	$ (5,944)	$ 6,288	$ 808	$ 830	$ (29,829)	$ 48,761	$ 15,022	$ 104,639
Percentage	0.18%	-0.10%	0.10%	0.01%	0.01%	-0.48%	0.79%	0.24%	1.69%

6.4 Decision Factor for Conclusion of the 2019 IRP

While the impact of adjustments detailed above are relatively limited, the number of identified adjustments shows this review process was a valuable exercise to help guide, shape, and inform the resolution of the 2019 IRP.

Following the conclusion of the review process, Idaho Power faced an important choice: To move forward with processing the *Amended 2019 IRP* and the associated Preferred Portfolio, knowing that the review showed minimal impact of the adjustments, or take the learnings from the review process and conduct a new analysis.

After considering these options and the immense importance of an accurate and trustworthy IRP, the company concluded that performing a new analysis for the 2019 IRP was the best and most logical path forward. The resulting and final IRP for this cycle, which incorporates all the adjustments identified in this review, is called the *Second Amended 2019 IRP*.

6.5 Recommendations for Future IRPs

The intended goal of this IRP review process was to identify adjustments and quantify their impact to conclude the 2019 IRP process. It became clear, however, that the learnings from this review could extend to future IRPs. To that end, the following improvements and insights were identified to ensure the IRP development process is more efficient, transparent, and accurate for future IRPs:

- **Future Reviews:** Elements of the review could be spun off to become valuable, routine features of IRP development. For example, an audit-style review of model inputs and input integration into AURORA could be an efficient way to ensure accuracy and reduce inadvertent errors in future IRP cycles.

- **Input Mapping:** The review of model inputs is made significantly easier by visual aids, such as flowcharts, that display the often-complex development of inputs into AURORA. Flowcharts are a valuable tool for streamlined IRP input validation and verification, but also for education and explanation with Idaho Power's customers and stakeholders interested in resource planning practices.

- **Subject Matter Experts:** The role of subject matter experts will be expanded to include an early review of the model to assess the reasonableness of the inputs, system settings to actual practices, and model results.

- **Tool Evolution and Support:** Energy Exemplar, the developers of AURORA, regularly release updated versions of the software. One of the latest updates enables co-optimization of results, which would allow co-optimization of the portfolio specific to Idaho Power and the WECC. This development could greatly increase the efficiency of the IRP process. Because changes to AURORA by its developers should be fully understood by Idaho Power before commencing the next IRP, Energy Exemplar's support services should be leveraged to the maximum extent.

7. CONCLUSION

The IRP Review Report is the culmination of six weeks of comprehensive study of Idaho Power's resource planning practices and modeling associated with the 2019 IRP cycle. The goal of the four-step review process was to deconstruct and examine the foundational elements of the 2019 IRP analysis—including model inputs and assumptions, model system settings, model verification and validation, and model outputs—and then identify actions to resolve the discovered issues.

In the course of the review, the company identified some appropriate adjustments to model inputs and treatment of data within the model. Assessed individually, the identified modeling adjustments showed limited impact to costs of select portfolios from the *Amended 2019 IRP*. Collectively, the adjustments also had a minimal impact on portfolio costs. Further, the collective adjustments did not change the ranking of the identified Preferred Portfolio against the best-performing non-B2H portfolio and the best-performing portfolio with later Bridger exit timing.

All identified issues are fully reflected in the company's final IRP for this cycle, the *Second Amended 2019 IRP*.

While undertaking this effort in the middle of an IRP under review was not ideal for everyone impacted by the resulting delay, Idaho Power is grateful for the opportunity to conduct such a thorough investigation of its approach and practices related to the IRP. The outcome of this review not only ensures the validity of the 2019 IRP, but also offers valuable lessons and insights that can be applied to future IRPs.