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December 30, 2021

VIA EMAIL AND U.S. MAIL

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

Re: Docket LC 78 – Idaho Power Company's 2021 Integrated Resource Plan ("IRP")

Attached for filing in the above-referenced docket is Idaho Power Company's Application and 2021 Integrated Resource Plan, with Appendices A, B and C. As discussed in the Application, Appendix D of the IRP will be filed by the end of the first quarter of 2022. Hard copies of this filing will be sent to the Oregon Public Utility Commission.

Please contact this office with any questions.

Thank you,

Suzanne Prinsen

Suzanne Prinsen
Legal Assistant

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 78

In the Matter of IDAHO POWER COMPANY'S 2021 Integrated Resource Plan.	))))))	**APPLICATION**

Idaho Power Company (Idaho Power or Company), in accordance with the Public Utility Commission of Oregon's (Commission) Order Nos. 89-507, 07-002, 07-747, and 12-013, hereby requests that the Commission issue an order acknowledging the Company's 2021 Integrated Resource Plan (IRP or Plan).

Idaho Power requests that the following people receive notices and communications with respect to this Application:

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I. INTRODUCTION

Idaho Power's 2021 IRP undertakes a comprehensive analysis of the optimal mix of both demand- and supply-side resources available to reliably serve customer demand and flexible capacity needs over the Plan's 20-year planning horizon from 2021 to 2040. Under Idaho Power's improved AURORA long-term capacity expansion (LTCE) approach—which Idaho Power utilized for the first time in this IRP—resources are selected by the model from a variety of supply- and demand-side options to develop portfolios that are least cost for various alternative scenarios. To ensure that the resulting portfolios provide customers with least-cost, least-risk resources, Idaho Power employed verification tests to validate the most economic portfolio under numerous variations of resources and timing. Moreover, to confirm that the AURORA-produced portfolios meet Idaho Power's reliability requirements, the Company measured each portfolio's reliability through the calculation of a portfolio loss of load expectation (LOLE) on an annual basis. Based on this analysis, Idaho Power selected a Preferred Portfolio and Short-Term Action Plan that are driven by and include the following core resource actions:

- Add 120 megawatts (MW) of solar photovoltaic (PV) capacity in 2022;
- Convert Bridger units 1 and 2 from coal to natural gas by summer 2024;
- Seek to acquire significant resources to meet capacity and energy needs in 2023 through 2027;
- Exit from Bridger unit 3 and Valmy unit 2 by year-end 2025;
- Energize B2H in 2026.

The complete 2021 IRP consists of five separate documents: (1) the 2021 Integrated Resource Plan; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2020 Annual Report; (4) Appendix C – Technical Appendix. By the end of the first quarter of 2022, Idaho Power will also provide an Appendix D – Transmission Supplement. A copy of the complete 2021 IRP (with the exception of Appendix D) is provided as Attachment 1 and can also be found on the Company's website at www.idahopower.com/irp. Appendix D will be filed and distributed to the service list in the first quarter of 2022. Interested parties may also request a single printed copy of the 2021 IRP by contacting irp@idahopower.com.

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II. IRP GOALS AND ASSUMPTIONS

The primary goals of Idaho Power's 2021 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period (2021-2040); (2) ensure the selected resource portfolio balances cost and risk, while including environmental considerations; (3) give balanced treatment to both supply-side resources and demand-side measures; and (4) involve the public in the planning process in a meaningful way.

The 2021 IRP assumes that during the 20-year planning period, Idaho Power will continue to be responsible for acquiring resources sufficient to serve its retail customers in its Idaho and Oregon service areas and will continue to operate as a vertically integrated electric utility. During the 20-year planning period, Idaho Power's load is forecasted to grow by an average of 1.4 percent per year for energy demand and 1.4 percent per year for peak-hour demand. Total customers are expected to increase from more than 600,000 in 2021 to 847,000 by 2040.

Hydroelectric generation remains a large part of Idaho Power's generation fleet; however, hydroelectric plants are subject to variable water and weather conditions. In response to public and regulatory input, Idaho Power continues to develop more conservative streamflow projections and planning criteria for use in resource adequacy planning.

The 2021 IRP examined demand-side management (DSM) programs, which are designed to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction. Idaho Power also continues to provide customers with tools and information to help them manage their own energy usage. The Company achieves these objectives through the implementation and careful management of incentive programs and through outreach and education.

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Idaho Power's resource planning process also evaluates transmission capacity as a resource to serve retail customers. Transmission projects are often regional resources, and Idaho Power coordinates transmission planning regionally as a member of NorthernGrid. The delivery of energy, both within the Idaho Power system and through regional transmission interconnections, is of increasing importance as regional penetration of variable energy resources and their associated intermittent production continues to increase. The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

Finally, Idaho Power engages with public stakeholders when developing its IRP. To incorporate stakeholder and public input, the Company worked with the Integrated Resource Plan Advisory Council (IRPAC), comprising members of the environmental community, major industrial customers, agricultural interests, representatives from both this Commission and the Idaho Public Utilities Commission, representatives from the Idaho Governor's Office of Energy and Mineral Resources, representatives from the Northwest Power and Conservation Council, and others. Many members of the public also attended and participated. A list of the 2021 IRPAC members can be found in Appendix C – Technical Report.

For the 2021 IRP, Idaho Power conducted twelve IRPAC meetings. The Company also maintained an online forum for stakeholders to submit requests for information, and for the Company to provide responses to information requests. The forum allowed stakeholders to develop their understanding of the IRP process, particularly its key inputs, which enabled more meaningful stakeholder involvement throughout the process.

III. IRP METHODOLOGY

Idaho Power's IRP is designed to ensure the Company has sufficient resources to reliably serve customer demand and flexible capacity needs over the 20-year planning period.

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A. Improved Capacity Expansion Modeling Approach

In Idaho Power's 2019 IRP, Idaho Power used AURORA's LTCE platform with varied success. The LTCE was able to optimize for the entire western interconnection; however, it was incapable of optimizing specifically for Idaho Power's service area. For this reason, the Company went through a manual optimization process to determine an Idaho Power Preferred Portfolio. The manual optimization approach complicated the IRP process and it raised questions on the part of the Commission and stakeholders. Therefore, in an effort to improve both the process and results for the 2021 IRP, as well as future IRPs, the Company worked with the software provider to add functionality allowing for co-optimization between the western interconnection and Idaho Power. As a result, the resource portfolios developed in the 2021 IRP were optimized entirely within the LTCE platform, without manual adjustments, specific to Idaho Power's balancing area.

As part of the 2021 IRP process, the Company formulated future scenarios based on economic, market, and regulatory considerations and then allowed the AURORA model to select the optimal resources to address the conditions in each scenario. The model selected from a wide variety of supply and demand-side resource options to develop optimal portfolios that meet a 15.5 percent planning margin, and regulated reserve requirements associated with balancing load, wind generation, and solar generation. The model can also simulate retirement of existing generation units, if economic, and can displace otherwise available resources that are higher cost.

To ensure that the AURORA-produced portfolios provide customers with affordable energy, Idaho Power employed verification tests to validate the most economic portfolio under numerous variations of resources and timing. To verify that the AURORA-produced portfolios meet Idaho Power's reliability requirements, Idaho Power measured each portfolio's reliability through the calculation of a portfolio LOLE. For those portfolios that did

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not achieve the minimum reliability threshold, an additional reliability resource requirement cost was added to the portfolio cost.

For each of the AURORA-developed portfolios, Idaho Power conducted a financial analysis of costs and benefits. The financial costs and benefits include:

- Construction costs
- Fuel costs
- Operations and maintenance costs
- Transmission upgrades associated with interconnecting new resource options
- Natural gas pipeline reservation or new natural gas pipeline infrastructure
- Projected wholesale market purchases and sales
- Anticipated environmental controls
- Market value of renewable energy certificates (REC) for REC-eligible resources

In addition, to enhance the risk-evaluation within the IRP, the Company worked with the IRPAC to develop four unique future scenarios. Idaho Power ultimately used these scenarios to test whether the decisions being made within the Action Plan window are robust across multiple futures. The four future scenarios are:

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

B. *Boardman to Hemingway*

Idaho Power's 2021 IRP continues to analyze the addition of the Boardman to Hemingway Transmission Line Project (B2H) to ensure that it remains a prudent resource. In the 2021 IRP, the Company evaluated B2H based on the Company owning 45 percent of the project, which represents a change from Idaho Power's share evaluated in the 2019 IRP. This increase in the Company's assumed ownership share is based upon ongoing negotiations among Idaho Power, PacifiCorp, and Bonneville Power Administration. A detailed update with regard to B2H will be provided as Appendix D, which will be filed with the Commission during the first quarter of 2022.

As part of the 2021 IRP, the Company provides an extensive evaluation of B2H compared to portfolios that do not include B2H, as well as several sensitivities of the project related to project cost contingency, Mid-Columbia market availability, and project timing. The Preferred Portfolio, which includes B2H, is significantly more cost-effective than the best alternative portfolio that did not include B2H, with the cost gap between the portfolios having an NPV difference of about $270 million. This gap provides substantial insulation to the various project risks that were evaluated.

C. Climate Change

Idaho Power's 2021 IRP includes a new chapter addressing both the mitigation of and adaption to climate change. In March of 2019, the Company announced a goal to provide 100% clean energy by 2045. Complementing this clean energy goal, the 2021 IRP shows that the Company will continue to rely on hydropower, plan to end reliance on coal-fired operations by year-end 2028, as well as continue to focus on energy efficiency and demand response programs, as they are deemed economical and reliable. This chapter of the IRP also addresses measures required to adapt to a changing climate, through risk mitigation and management. The 2021 IRP also includes a variety of modeling scenarios to conceive of a climate change future and/or future with climate change policies or regulations.

IV. PREFERRED RESOURCE PORTFOLIO

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The Preferred Portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost and risk over the 2021 to 2040 planning period.

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Using the AURORA LTCE model, Idaho Power produced optimized portfolios:

- With and without B2H;
- With and without portions of the Gateway West project;
- Allowing the model to choose Bridger Coal Plant exit date and natural gas conversion date assumptions based on Idaho Power's economics;
- Aligning with PacifiCorp's Bridger Coal Plant exit date and natural gas conversion date assumptions.[1]

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

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

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

[1] *In re PacifiCorp, 2021 Integrated Resource Plan*, Docket LC 77, Updated Vol. 1 at 299, 322 (Sep 15, 2021).

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

Based on all of this analysis, Idaho Power selected its Preferred Portfolio, which is identified as the Base with B2H portfolio. This Preferred Portfolio incorporates positive changes toward clean, low-cost resources, with an increased focus on system adequacy.

V. ACTION PLAN (2021-2027)

The Action Plan for the 2021 IRP reflects near-term actionable items of the Preferred Portfolio necessary to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to our customers into the future. As noted above, the core resource actions include:

- The addition of 120 MW of solar photovoltaic capacity in 2022;
- Conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024;
- Seek to acquire significant resources to meet capacity and energy needs in 2023 through 2027;
- Exit from Bridger unit 3 and Valmy unit 2 by 2025;
- B2H online in 2026.

Below is a summary of the 2021 IRP's Action Plan items through 2027:

Year	Action
2022	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state commissions.
2022	Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs.
2022–2023	Jackpot Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.

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Year	Action
2022–2024	Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger units 1 and 2. The conversion is targeted before the summer peak of 2024.
2022–2025	Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.
2022–2025	Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.
2022–2025	Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.
2022–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2022–2027	Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.
2022–2027	Work with large-load customers to support their energy needs with solar resources.
2022–2027	Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.
2025	Exit Valmy Unit 2 by December 31, 2025.
2025–2026	Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

VI. COMPLIANCE WITH ORDER NO. 21-184

In its acknowledgement of Idaho Power's 2019 IRP in Order No. 21-184, the Commission directed Idaho Power to provide additional analysis and/or discussion of a number of issues in its 2021 IRP.[2] Some of the key directions are discussed below.

First, the Commission directed Idaho Power to provide the results of its analysis of its proposed exit from Valmy unit 2.[3] The results of that analysis were filed in Docket LC 74 on August 4, 2021, and the Company restudied that exit data as part of the AURORA LTCE performed in this IRP. Those studies did not select an exit date earlier than 2025.[4]

Second, the Commission asked for additional analysis on exit dates for Bridger units 1 and 2 without SCR investments.[5] Idaho Power performed that analysis, which resulted in the following exit dates:

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[2] *In re Idaho Power Company, 2019 Integrated Resource Plan*, Docket LC 74, Order No. 21-184 at 1, Appendix A at 2-5 (June 4, 2021).
[3] Order No. 21-184 at 9, Appendix A at 3, 25.
[4] Idaho Power Company's Valmy Unit 2 Exit Analysis (Aug. 4, 2021).
[5] Order No. 21-184 at 11, Appendix A at 3, 23.

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- Unit 1: Allowed to exit year-end 2023 or convert to natural gas. If converted to natural gas, exit set for 2034;
- Unit 2: Allowed to exit between year-end 2023 and year-end 2026, or convert to natural gas as early as 2023. If converted to natural gas, exit set for 2034;
- Unit 3: Can exit no earlier than year-end 2025 and no later than year-end 2034;
- Unit 4: Can exit no earlier than year-end 2027 and no later than year-end 2034.

Third, the Commission asked Idaho Power to explain and support its cost contingency for B2H.[6] The Company performed sensitivities that showed that the cost of B2H would need to increase well over 30 percent above current estimates before the project would no longer be cost-effective.

Fourth, the Commission asked Idaho Power to model expanded demand response,[7] which resulted in approximately 580 MW being identified in the Company's service area. This includes 300 MW of Idaho Power's updated demand response programs, with an additional 280 MW available for selection in AURORA when analyzing future load and resource balance.

Fifth, the Commission asked the Company to improve its optimization techniques,[8] which the Company has achieved as discussed above.

Sixth, the Commission asked Idaho Power to eliminate the cap on battery storage.[9] As a result, the 2021 IRP's Preferred Portfolio includes 1,685 MW of battery storage resources.

[6] Order No. 21-184 at 16-17, Appendix A at 2, 17-19.
[7] Order No. 21-184 at 17-18, Appendix A at 4, 41.
[8] Order No. 21-184, Appendix A at 4, 32.
[9] Order No. 21-184, Appendix A at 49.

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At the Commission's request, the Company also performed additional analysis related to its load forecast.[10]

A table showing each of the Commission's directions, and a discussion of the Company's compliance, is attached as Attachment 2.

VII. REQUEST FOR ACKNOWLEDGMENT

Having fulfilled the Commission's guidelines and directions, Idaho Power respectfully requests that the Commission issue an order acknowledging the Company's 2021 IRP and finding that the 2021 IRP meets both the procedural and substantive requirements of Order Nos. 89-507, 07-002, 07-747, and 12-013.

DATED this 30th day of December 2021.

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Lisa F. Rackner
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IDAHO POWER COMPANY

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[10] Order No. 21-184 at 18, Appendix A at 4, 35-38; Idaho Power Company's Final Comments at 70 (Feb. 5, 2021).

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 78

IDAHO POWER COMPANY

Attachment 1

2021 Integrated Resource Plan

December 30, 2021

IDAHO POWER®
An IDACORP Company

DECEMBER • 2021

IRP

INTEGRATED RESOURCE PLAN

A VIEW
FROM ABOVE

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

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

AgI—Silver Iodide

akW—Average Kilowatt

aMW—Average Megawatt

ATC—Available Transfer Capacity

B2H—Boardman to Hemingway

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

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

CAISO—California Independent System Operator

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CO_2—Carbon Dioxide

CPCN—Certificate of Public Convenience and Necessity

CSPP—Cogeneration and Small-Power Producers

CWA—*Clean Water Act of 1972*

DC—Direct Current

DEQ—Department of Environmental Quality

DER—Distributed Energy Resources

DOE—Department of Energy

DPO—Draft Proposed Order

DSM—Demand-Side Management

DSP—Distribution System Planning

E3—Energy and Environmental Economics, Inc.

EE—Energy Efficiency

EFOR— Effective Forced Outage Rate

EFSC—Energy Facility Siting Council

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

ELCC—Effective Load Carrying Capability

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

MWh—Megawatt-Hour

NEPA—*National Environmental Policy Act of 1969*

NERC—North American Electric Reliability Corporation

NOx—Nitrogen Oxide

NPV—Net Present Value

NRC—Nuclear Regulatory Commission

NREL—National Renewable Energy Laboratory

NWPCC—Northwest Power and Conservation Council

NYMEX—New York Mercantile Exchange

O&M—Operation and Maintenance

OATT—Open-Access Transmission Tariff

ODOE—Oregon Department of Energy

OPUC—Oregon Public Utility Commission

pASC—Preliminary Application for Site Certificate

PAC—PacifiCorp

PCA—Power Cost Adjustment

PGE—Portland General Electric

PM&E—Protection, Mitigation, and Enhancement

PPA—Power Purchase Agreement

PTC—Production Tax Credit

PURPA—*Public Utility Regulatory Policies Act of 1978*

PV—Photovoltaic

QF—Qualifying Facility

REC—Renewable Energy Certificate

RFP—Request for Proposal

RICE—Reciprocating Internal Combustion Engine

ROD—Record of Decision

ROR—Run-of-River

RPS—Renewable Portfolio Standard

RTF—Regional Technical Forum

SB—Senate Bill

SCCT—Simple-Cycle Combustion Turbine

SCR—Selective Catalytic Reduction

SMR—Small Modular Reactor

SO_2—Sulfur Dioxide

SRBA—Snake River Basin Adjudication

SWIP—South West Intertie Project

T&D—Transmission and Distribution

TRC—Total Resource Cost

UCT—Utility Cost Test

USBR—United States Bureau of Reclamation

USFS—United States Forest Service

VER—Variable Energy Resources

WECC—Western Electricity Coordinating Council

An IDACORP Company

IRP REPORT:

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

Introduction

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

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

IRP Methodology Improvements

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

As in prior planning cycles, Idaho Power used Energy Exemplar's AURORA model for the 2021 IRP. Under AURORA's Long-Term Capacity Expansion (LTCE) modeling approach, resources are selected from a variety of supply- and demand-side resource options to develop portfolios that are least-cost for the given alternative future scenarios with the objective of meeting a 15.5% planning margin and regulating reserve requirements associated with balancing load, wind, and solar-plant output. The model can also select to exit existing coal generation units, as well as build resources based on economics absent a defined capacity need. The LTCE modeling process is discussed in further detail in Chapter 9.

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

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

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

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

For the AURORA-developed portfolios, Idaho Power conducted a financial analysis of costs and benefits. The financial costs and benefits include:

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

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

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

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

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

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

Portfolio Analysis Overview

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

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

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

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

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

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

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

Table 1.1 Preferred Portfolio additions and coal exits (MW)

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

Preferred Portfolio Changes from the 2019 IRP

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

Table 1.2 2021 IRP comparison to the 2019 IRP

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

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

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

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

Action Plan (2021–2027)

The Action Plan for the 2021 IRP reflects near-term actionable items of the Preferred Portfolio. The Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to our customers into the future. The current regional electric market, regulatory environment, pace of technological change and Idaho Power's goal of 100% clean energy by 2045 make the 2021 Action Plan especially relevant.

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

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

The Action Plan is the result of the above resource actions and portfolio attributes, which are discussed in the following sections. Further discussion of the core resource actions and attributes of the Preferred Portfolio is included in Chapter 11. A chronological listing of the near-term actions follows in Table 1.3.

Table 1.3 Action Plan (2021–2027)

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

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

Bridger Unit Conversions and Exits

Idaho Power owns one-third of Bridger units 1–4, and PacifiCorp owns the remaining two-thirds and is the plant operator. In its 2021 IRP, PacifiCorp concluded it would be cost-effective to convert Bridger units 1 and 2 to natural gas beginning in 2024 while continuing to operate units 3 and 4 as coal units through 2037. Idaho Power and PacifiCorp have not developed contractual terms that would be necessary to allow for the potential earlier exit or conversion to a non-coal fuel source by one party or both parties. Any new contractual terms may impact costs and assumptions, and therefore the specific timing of exits identified in the 2021 IRP.

For the 2021 IRP, Idaho Power used AURORA's LTCE model to determine the best Bridger operating option specific to Idaho Power's system subject to the following constraints:

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

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

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

Boardman to Hemingway

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

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

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

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

IRP REPORT:

BACKGROUND

1. BACKGROUND

Integrated Resource Plan

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

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

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

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

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

Idaho Power's resource planning process evaluates additional stand-alone transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and Idaho Power coordinates transmission planning as a member of NorthernGrid. Idaho Power is obligated under Federal Energy Regulatory Commission (FERC) regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers and Idaho Power retail customers. The delivery of energy, both within Idaho Power's system and through regional transmission interconnections, is of increasing importance for several reasons. First, adequate transmission is essential for robust participation in the Energy

Imbalance Market (EIM). Second, it is necessary to unlock geographic resource diversity benefits for Variable Energy Resources (VER). The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The IRPAC meets regularly during the development of the resource plan, and the meetings are open to the public. Members of the council include staff from the IPUC and OPUC; political, environmental, and customer representatives; and representatives of other public-interest groups. Many members of the public also participate in the IRPAC meetings. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2021 IRPAC members can be found in *Appendix C—Technical Report*.

For the 2021 IRP, Idaho Power facilitated nine IRPAC meetings and three additional workshops. All 2021 IRPAC meetings were conducted virtually, which resulted in increased and more diverse participation of members and the general public. The company received positive feedback from IRPAC members that the virtual forum was logistically easier and aided in the presentation and review of materials.

To further enhance engagement, Idaho Power also maintained an online webpage for stakeholders to submit requests for information and for Idaho Power to provide responses. The webpage allowed stakeholders to develop their understanding of the IRP process, particularly its key inputs, consequently enabling more meaningful stakeholder involvement. The company made presentation slides and other materials used at the IRPAC meetings, in addition to the question-submission portal and other IRP documents, available to the public on its website at idahopower.com/IRP.

IRP Methodology

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

Cost

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

Risk

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

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

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

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

The second method employed by the 2021 IRP is an analysis of stochastic risk. Stochastic analyses help quantify the sensitivity and risk associated with variables over which Idaho Power has little or no control. For more information, see Chapter 10.

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

Modeling

Due to the complexity involved in an analysis that includes a 20-year forecast for energy demand, fuel prices, resource costs and more, Idaho Power uses modeling software to generate and optimize resources selected in portfolios. For the 2021 IRP, the company utilized the

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

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

Validation and Verification

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

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

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

Energy Risk Management Policy

While the 2021 IRP addresses Idaho Power's long-term resource needs, near-term energy needs are evaluated in accordance with the company's *Energy Risk Management Policy* and *Energy Risk Management Standards*. The risk management standards were collaboratively developed in 2002 among Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The risk management standards provide guidelines for Idaho Power's physical and financial hedging and are designed to systematically identify, quantify, and manage the exposure of the company and its customers to uncertainties related to the energy markets in which Idaho Power is an active participant. The risk management standards specify an

18-month load and resource review period, and Idaho Power's Risk Management Committee assesses the resulting operations plan monthly.

An IDACORP Company

IRP REPORT:

POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

2. POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

Idaho Strategic Energy Alliance

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

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

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

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

Idaho Energy Landscape

In 2021, the ISEA prepared the *2021 Idaho Energy Landscape Report* to help Idahoans better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.[1]

The *2021 Idaho Energy Landscape Report* concludes, "The strength of Idaho's economy and the quality of life in Idaho depend upon access to affordable and reliable energy resources."[1] The report provides information about energy resources, production, distribution, and use in the state. The report also discusses the need for reliable, affordable, and sustainable energy for individuals, families, and businesses while protecting the environment to achieve sustainable economic growth and maintain Idaho's quality of life.

The 2021 report finds a weakening correlation between economic growth and energy consumption due to technological changes and the increased use of energy efficiency. Idaho's gross domestic product grew 4.8% annually from 1998 to 2018, yet Idaho's energy consumption (transportation, heat, light, and power) grew just 0.5% annually from 1998 to 2018.[1]

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

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

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

State of Oregon 2020 Biennial Energy Report

In 2017, the Oregon Department of Energy (ODOE) introduced House Bill (HB) 2343, which charges the ODOE to develop a new biennial report to inform local, state, regional, and federal energy policy development and energy planning and investments. The *2020 Biennial Energy Report*[2] provides foundational energy data about Oregon and examines the existing policy landscape while identifying options for continued progress toward meeting the state's goals in the areas of climate change, renewable energy, transportation, energy resilience, energy efficiency, and consumer protection.

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

The main theme of the 2020 biennial report was Oregon's transition to a low-carbon economy. According to the report, achieving Oregon's energy and climate goals, while protecting consumers, will take collaboration among state agencies, policy makers, state and local governments, and private-sector business and industry leaders.[3]

FERC Relicensing

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

Hells Canyon Dam

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

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

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

Idaho Power's hydroelectric generating capacity and 30% of the company's total generating capacity. The original license for the HCC expired in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under annual licenses issued by FERC. The HCC provides clean energy to Idaho Power's system, supporting Idaho Power's long-term clean energy goals. The HCC also provides flexible capacity critical to the successful integration of VERs, further enabling the achievement of Idaho Power's clean energy goals.

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

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

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

In addition to the relicensing of the HCC, Idaho Power is also relicensing its American Falls hydroelectric project. Its FERC license expires in 2025.

Relicensing activities include the following:

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

- Preparing and conducting studies on fish, wildlife, recreation, archaeological resources, historical flow patterns, reservoir operations and load shaping, forebay and river sedimentation, and reservoir contours and volumes
- Analyzing data and reporting study results
- Preparing all necessary reports, exhibits, and filings to support ongoing regulatory processes related to the relicensing effort

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

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

Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects. Idaho Power is dedicated to the vigorous defense of its water rights. Idaho Power's ongoing participation in water-right issues and studies is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.

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

The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of the State of Idaho in October 1984. The Swan Falls Agreement resolved a struggle over the company's water rights at the Swan Falls Hydroelectric Project (Swan Falls Project). The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled Idaho Power to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

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

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

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying the water rights held in trust by the State of Idaho are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the State of Idaho and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the State of Idaho are actively involved in those discussions. The settlement recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as managed aquifer-recharge projects—to benefit agricultural development and hydroelectric generation.

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

Water-management activities for the ESPA are currently being driven by the recent agreement between the Surface Water Coalition and the Idaho Ground Water Appropriators. This agreement settled a call by the Surface Water Coalition against groundwater appropriators for the delivery of water to its members at the Minidoka and Milner dams. The agreement provides a plan for the management of groundwater resources on the ESPA, with the goal of improving aquifer levels and spring discharge upstream of Milner Dam. The plan provides short- and long-term aquifer level goals that must be met to ensure a sufficient water supply for the Surface Water Coalition. The plan also references ongoing management activities, such as aquifer recharge. The plan provides the framework for modeling future management activities on the ESPA. These management activities are included in the modeling of hydropower production through the IRP planning horizon.

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

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

Spackman said creating a GWMA will embrace the terms of a historic water settlement between the Surface Water Coalition and groundwater users, but the GWMA for the ESPA will also seek to bring other water users under management who have not joined a groundwater district, including some cities.

Variable Energy Resource Integration

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

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

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

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

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

For the 2021 IRP analysis, the 2020 VER study defined the hourly reserves needed to reliably operate the system based on current and future quantities of solar and wind generation and load forecasted by season and time of day. The reserves are defined separately, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2021 IRP include defining hourly reserve requirements for “Load Up,” “Load Down,” “Solar Up,” “Solar Down,” “Wind Up,” and “Wind Down.”

Oregon Community Solar Program

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

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

Under the Oregon Community Solar Program rules, Idaho Power’s initial capacity tier is 3.3 MW. As of the date of this IRP filing, Idaho Power has executed all the necessary agreements with Verde Light, a 2.95-MW project that intends to participate in the community solar program, with a planned in-service date of July 2022. The company believes the project is well positioned to obtain the necessary certifications to participate in the program. The proposed 2.95-MW project will use all but 305 kilowatts (kW) of Idaho Power’s initial capacity allocation.

Additionally, Order No. 17-232 requires Idaho Power to: 1) include all energized community solar projects participating in the community solar program in its generation mix included in its IRP and 2) include forecasts of market potential for community solar projects when assessing the load-resource balance in the IRP. Because the potential project is not planning to be operational until mid-2022, the resource has not been included in this IRP. Once operational, the project will be included as part of the generation mix in future IRP cycles.

Renewable Energy Certificates

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

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

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

REC prices depend on many factors, including the following:

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

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

Clean Energy Your Way

On Thursday, December 2, 2021, the company filed an application with the IPUC to expand optional customer clean energy offerings through the Clean Energy Your Way Program. Idaho Power has long supported customers’ individual goals and initiatives to achieve clean energy through various program offerings, as well as becoming one of the first investor-owned utilities to proactively establish a 100% clean energy goal by 2045. This request will allow the company to better meet the needs of the growing number of customers and communities pursuing or exploring sustainability targets, such as powering their operations on 100% renewable energy by the end of the decade—if not sooner.

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

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

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

Clean Energy Your Way—Flexible

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

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

Clean Energy Your Way—Subscription

The Subscription offering will provide opportunities for business and residential customers in Idaho to receive an amount of renewable energy equal to either 50% or 100% of their historic average annual energy use by subscribing to a new renewable resource. This resource would be built upon approval of the IPUC—the type and timing of the resource would be determined through a subsequent phase of the implementation process, with size dependent upon customer interest. Subscription terms are intended to provide customers the ability to "opt-in and opt-out" based on their individual preferences. Terms for residential customers could be as short as monthly, and terms for business customers would range from 5 to 20 years.

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

Clean Energy Your Way—Construction

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

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

Renewable Portfolio Standard

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established a Renewable Portfolio Standard (RPS) for electric utilities and retail electricity suppliers. Under the Oregon RPS, Idaho Power is classified as a smaller utility because the company's Oregon customers represent less than 3% of Oregon's total retail electric sales. In 2020 per United States Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.4% of Oregon's total retail electric sales. As a smaller utility in Oregon, Idaho Power will likely have to meet a 5% RPS requirement beginning in 2025.

In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25% by 2025 to 50% renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change. Additionally, the Oregon Legislature in 2021 passed House Bill 2021, which sets greenhouse gas emissions reduction requirements associated with electricity sold to utility customers. Idaho Power is exempt from the conditions of this bill, as the company has fewer than 25,000 retail customers in Oregon.

The State of Idaho does not currently have an RPS.

Carbon Adder/Clean Power Plan

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

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

In January 2021, the new presidential administration issued several executive orders to establish new federal environmental mandates, revoke several existing executive orders, and require agencies to review regulations related to environmental matters issued by the previous presidential administration. One executive order rejoined the United States to the Paris Agreement on climate change, which requires commitments to reduce GHG emissions, among other things. A more recent executive order, signed by President Biden on December 8, 2021, seeks to leverage government actions and procurement to further the clean energy transition. Among several directives in the order are requirement to achieve net-zero emissions from federal procurement and from overall federal operations by 2050.[4]

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

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

IRP REPORT:

CLIMATE CHANGE

3. CLIMATE CHANGE

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

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

Climate Change Mitigation

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

In March 2019, Idaho Power announced a goal to provide 100% clean energy by 2045. This goal furthers Idaho Power's legacy as a leader in clean energy. The key to achieving this goal of 100% clean energy is the company's existing backbone of hydropower—our largest energy source—as well as the plan contained in the Preferred Portfolio to continue reducing carbon emissions by ending reliance on coal plants by year-end 2028.

The Preferred Portfolio identified in this 2021 IRP reflects a clean mix of generation and transmission resources that ensures reliable, affordable energy using technologies available today. Achieving our 100% clean energy goal, however, will require technological advances and reductions in cost, as well as a continued focus on energy efficiency and demand-response programs. As it has over the past decade, the IRPAC will continue to play a fundamental role in updating the IRP every two years, including analyzing new and evolving technologies to help the company on its path toward a cleaner tomorrow while providing low-cost, reliable energy to our customers.

Idaho Power Carbon Emissions

Limiting the impact of climate change requires reducing GHG emissions, primarily CO_2. Idaho Power's CO_2 emission levels have historically been well below the national average for the 100 largest electric utilities in the United States, both in terms of emissions intensity (pounds per megawatt-hour [MWh] generation) and total CO_2 emissions (tons). The overall declining trend of carbon demonstrates Idaho Power's commitment to reducing emissions.

This is shown in the graph 3.1 and 3.2 with the dashed black line indicating the long-term trend and the green line indicating the actual annual amounts.

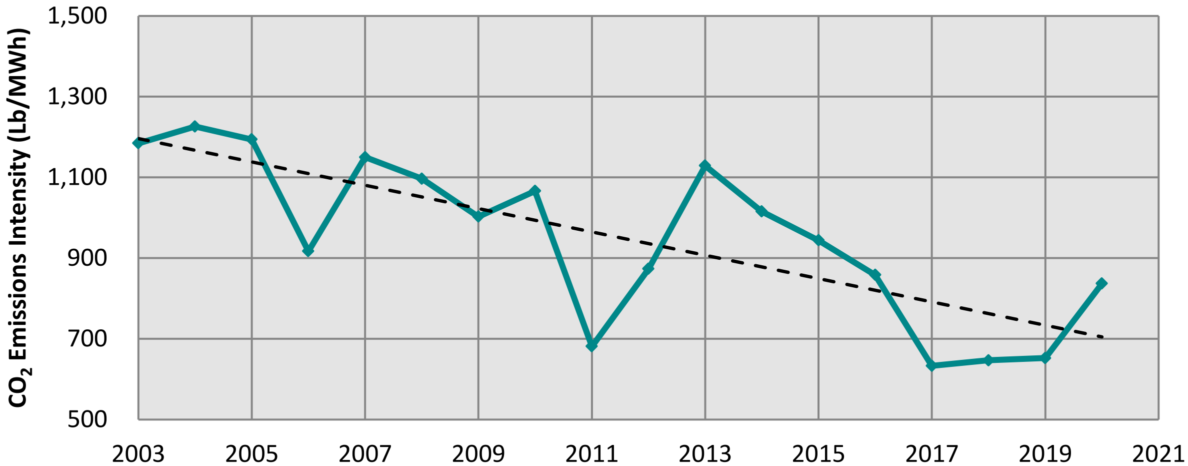

Figure 3.1 Estimated Idaho Power CO_2 emissions intensity

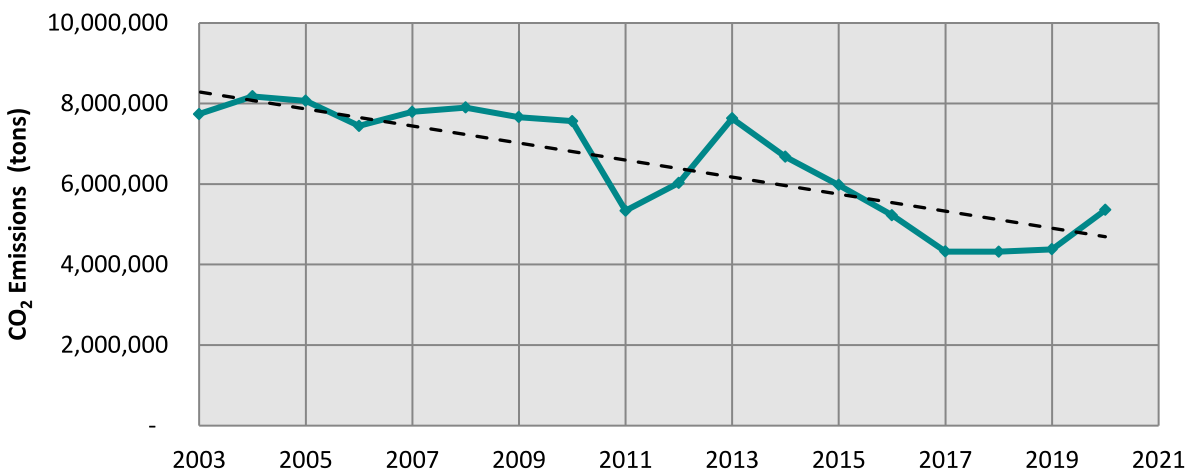

Figure 3.2 Estimated Idaho Power CO_2 emissions

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

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

The portfolio analysis performed for the 2021 IRP assumes carbon emissions are subject to a per-ton cost of carbon. The carbon cost forecasts are provided in Chapter 9, while the projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 10.

Energy Mix

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

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

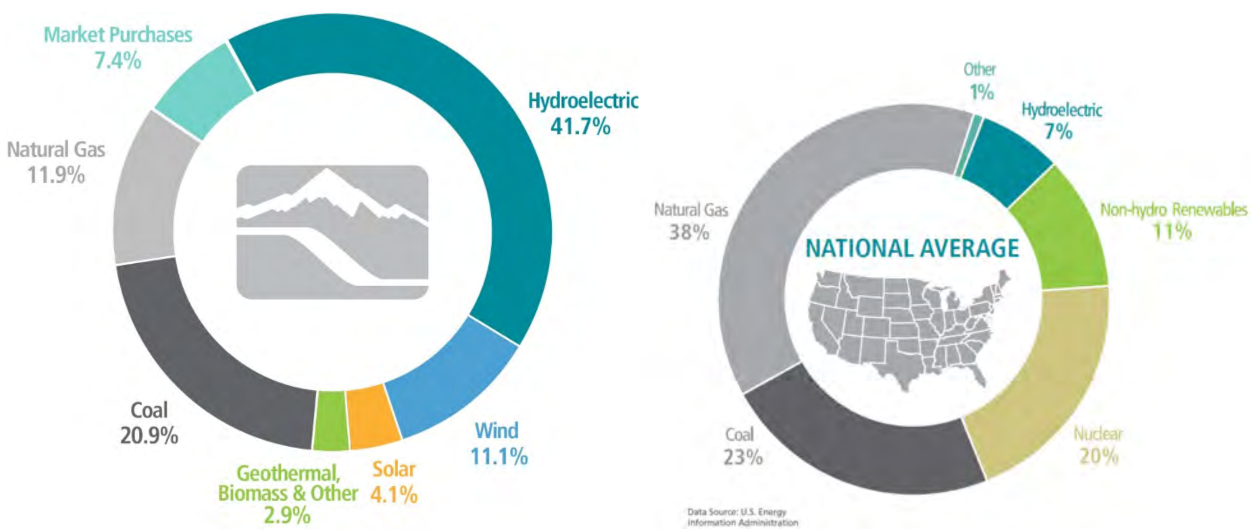

Figure 3.3 Idaho Power's 2020 energy mix compared to the national average

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

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

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

Climate Change Adaptation

As noted earlier, climate change adaptation relates to steps or measures that may need to be taken to adapt to a changing climate. To understand what these steps might be first requires understanding the potential regional impacts of climate change that Idaho Power may experience. To this end, Idaho Power stays current on climate change research and analysis both generally and specific to the Pacific Northwest. The sixth assessment report from the United Nations' Intergovernmental Panel on Climate Change (IPCC) states "Human-induced climate change is already affecting many weather and climate extremes in every region across the globe. Evidence of observed changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones… has strengthened."[6]

More regionally focused studies have assessed the potential impact of climate change on the Pacific Northwest. The Fourth National Climate Assessment[7] and the River Management Joint Operating Committee (RMJOC) [8] addressed water availability in the region under multiple climate change and response scenarios. Both reports highlight the uncertainty related to future climate projections. However, many of the model projections show warming temperatures and increased precipitation into the future.

In the 2021 IRP, Idaho Power approached climate change risk in two ways: through adjusted modeling inputs and scenarios and then with specific scenarios to understand portfolio impacts as a result of potential future climate change policies. Both approaches are summarized below and detailed in later chapters of this report.

Risk Identification and Management

Identification of and response to specific risks are managed via Idaho Power's annual Enterprise Risk and Compliance Assessment, which includes a robust review of current and emerging regulations and external factors impacting the company's internal operations in the areas of technology, legal, market, weather, reputation, and safety, among other risks. Management of each risk is identified and can include internal risk oversight by an internal department, committee, internal or external auditor process review, and Board of Directors oversight.

Climate change-specific risks are an evolving category that includes, but may not be limited to, changes in customer usage and hydro generation due to changing weather conditions and

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

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

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

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

Weather Risk

Changing and severe weather conditions as a result of climate change can adversely affect Idaho Power's operating results and cause them to fluctuate seasonally. Climate change could also have significant physical effects in Idaho Power's service area, such as increased frequency and severity of storms, lightning, droughts, heat waves, fires, floods, snow loading, and other extreme weather events. These events and their associated impacts could damage transmission, distribution, and generation facilities, causing service interruptions and extended outages, increasing costs and other operating and maintenance expenses—including emergency response planning and preparedness expenses—and limiting Idaho Power's ability to meet customer energy demand.

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

Wildfire Risk

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

The risk of more extensive or worsening wildfires is linked to weather-related climate risk. To manage wildfire-related risk, Idaho Power has developed a Fire Potential Index (FPI) tool based on original work completed by San Diego Gas and Electric, the United States Forest

Service, and the National Interagency Fire Center and modified for Idaho Power's Idaho and Oregon service area.

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

The FPI reflects key variables, such as the state of native vegetation across the service area, fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value, and those individual numeric values are summed to generate a Fire Potential value from zero to 16. That final value indicates the degree of fire threat expected for each of the seven days included in the forecast. Green, Yellow, or Red FPI scores reflect low, medium, and high levels of weather-related risk. The FPI is discussed in greater detail, along with the company's full list of wildfire mitigation measures, in Idaho Power's Wildfire Mitigation Plan (WMP). The WMP will be reviewed annually in advance of each fire season.[9]

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

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

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

Water and Hydropower Generation Risk

Factors contributing to lower hydropower generation can increase costs and negatively impact Idaho Power's financial condition and results of operations, as the company derives a significant portion of its power supply from its hydropower facilities.

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

Water supply within the Snake River Basin is primarily snowpack driven. To increase the amount of snow that falls in drainages that feed the Snake River—subsequently benefiting hydropower generation, irrigation, recreation, water quality and other uses—Idaho Power collaboratively conducts a successful cloud-seeding program in the Snake River Basin. In addition, Idaho Power provides forecasting and meteorological data support.

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

Policy Risk

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

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

Oregon service area. As a result, the company did not model HB 2021 requirements for Idaho Power's portfolio.

At the time of the 2021 IRP, state-level climate policies did not exist in Idaho and did not apply to Idaho Power in Oregon. Similarly, federal climate legislation has not been passed by Congress. However, the company believes that climate- and emissions-related policies will emerge in future years. To account for this expected future, the company models multiple scenarios with varying prices on carbon. These scenarios are detailed in Chapter 9 of this report.

Modeling Climate Risks in the IRP

While the above referenced climate-related risks are all addressed and accounted for in different operational ways by Idaho Power, the company also extended climate-related risk assessment to the 2021 IRP. Specifically, the company conducted additional scenarios to explore the impact these events would have on Idaho Power's system. These scenarios are summarized below and detailed in Chapter 9.

The company conducted a Rapid Electrification scenario at the request of IRPAC members. This scenario was developed to determine what kind of adjustments would need to be made to accommodate a very rapid transition toward electrification. This rapid transition includes increasing the electric vehicle forecast and the penetration of electric heat pumps for building heating and cooling each by a factor of 10. This aggressive forecast assumes over half a million electric vehicles as well as adoption of an 80% penetration of heat pump technology at residences within the company's service area by 2040.

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

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

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

An IDACORP Company

IRP REPORT:

IDAHO POWER TODAY

4. IDAHO POWER TODAY

Customer Load and Growth


Residential construction growth in southern Idaho.

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

Average firm load increased from 1,438 average MW (aMW) in 1996 to 1,809 aMW in 2020 (load calculations exclude the load from the former special contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 4.1 and Table 4.1. The data in Table 4.1 suggests each new customer adds over 5.0 kW to the peak-hour load and over 3 average kW (akW) to the average load.

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

Idaho Power anticipates adding approximately 13,300 customers each year throughout the 20-year planning period. The anticipated load forecast for the entire system predicts summer peak-hour load requirements will grow nearly 55 MW per year, and the average-energy requirement is forecast to grow about 30 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

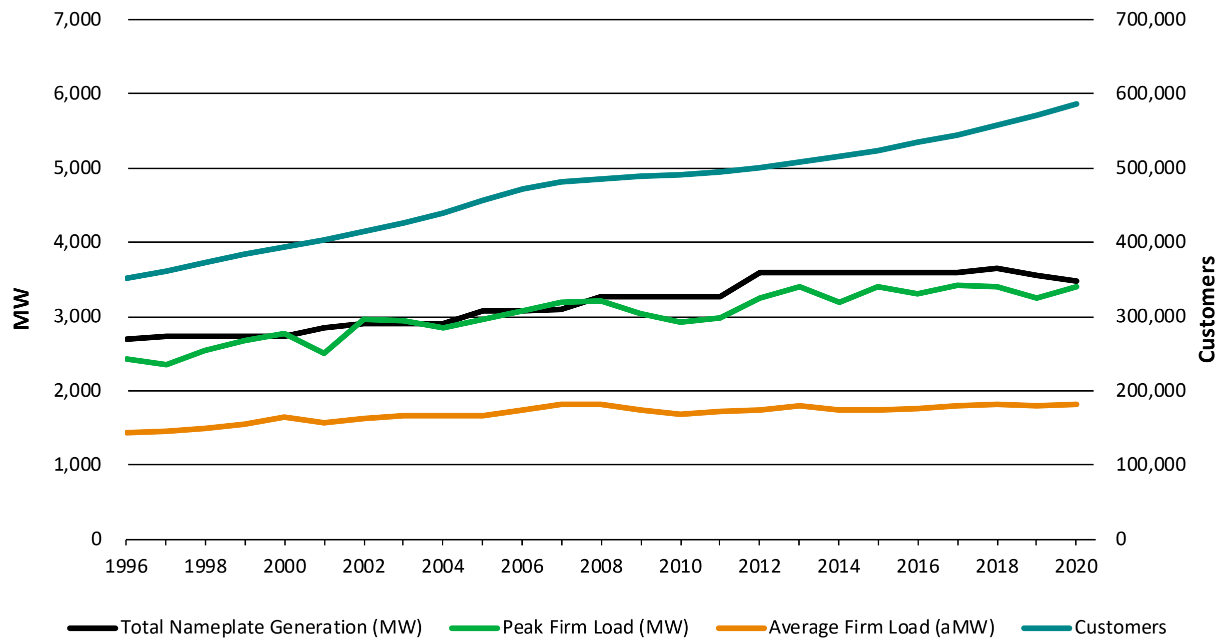

Figure 4.1 Historical capacity, load, and customer data

Table 4.1 Historical capacity, load, and customer data

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

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

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

2 Reported nameplate capacity aggregation methodology changed for 2020.

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

2020 Energy Sources

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

Existing Supply-Side Resources

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

Table 4.2 Existing resources

Resource	Type	Nameplate Capacity (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	675.0	Hells Canyon
C. J. Strike	Hydroelectric	82.8	Mid-Snake
Cascade	Hydroelectric	12.4	North Fork Payette
Clear Lake	Hydroelectric	2.5	South Central Idaho
Hells Canyon	Hydroelectric	391.5	Hells Canyon
Lower Malad	Hydroelectric	13.5	South Central Idaho
Lower Salmon	Hydroelectric	60.0	Mid-Snake
Milner	Hydroelectric	59.4	Upper Snake
Oxbow	Hydroelectric	190.0	Hells Canyon
Shoshone Falls	Hydroelectric	14.7	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake

Resource	Type	Nameplate Capacity (MW)	Location
Thousand Springs	Hydroelectric	6.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Jim Bridger[10]	Coal	707.0	Southwest Wyoming
North Valmy[11]	Coal	134.0	North Central Nevada
Langley Gulch	Natural Gas—CCCT	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT	164.2	Southwest Idaho
Danskin	Natural Gas—SCCT	261.4	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,388.9**	

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

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,773 MW and median annual generation equal to approximately 820 aMW, or 7.2 million MWh (1991–2020).

Hells Canyon Complex

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

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

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

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

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

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

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood risk management on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood risk management guidance from the United States Army Corps of Engineers as required in Article 42 of the existing FERC license.

After flood risk management requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

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

As part of a 2005 interim HCC relicensing agreement, Idaho Power agreed to provide up to 237,000 acre-feet of water from Brownlee Reservoir for flow augmentation, in addition to the federal flow augmentation releases. Idaho Power uses its best efforts to hold Brownlee Reservoir at or near full elevation (approximately 2,077 feet above mean sea level) through June 20. Thereafter, Brownlee Reservoir is drafted to elevation 2,059 (releasing up to 237,000 acre-feet) by August 7. Although the portion of the 2005 interim agreement relating to flow augmentation releases has expired, Idaho Power has continued to provide these flow augmentation releases annually through 2021.

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

Upper Snake and Mid-Snake Projects

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

Water-Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the hydroelectric production is needed are especially beneficial. Acquiring water through the Idaho Department of Water Resources' Water Supply Bank[12] also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC. The company does not currently have any standing water lease agreements. However, single-year leases from the Upper Snake Basin are occasionally available, and the company plans to continue to evaluate potential water lease opportunities in the future.

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

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the Upper Snake River Basin above Milner Dam. Idaho Power has continued to collaborate with the IWRB and water users in the Upper Snake, Boise, and Wood River basins to expand the target area to include those watersheds.

Cloud seeding ground generator

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

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

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

AgI particles are very efficient ice nuclei, allowing minute quantities to have an appreciable increase in precipitation. It has been used as a seeding agent in numerous western states for decades without any known harmful effects.[13] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1% and 22% annually, with an annual average of 11.3%. Idaho Power estimates cloud seeding, on average, provides an additional 415,000 acre-feet in the Upper Snake River, 105,000 acre-feet in the Wood River Basin, 264,000 acre-feet in the Boise Basin, and 221,000 acre-feet from the Payette River Basin, for a total average annual benefit of 1,006,000 acre-feet. At program build-out (including additional aircraft and remote ground generators), Idaho Power estimates additional runoff, on average, from the Payette, Boise, Wood, and Upper Snake projects will total

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

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

Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment (SNOWIE) was a joint project between the National Science Foundation and Idaho Power. Researchers from the universities of Wyoming, Colorado, and Illinois used Idaho Power's operational cloud seeding project, meteorological tools, and equipment to identify changes within wintertime precipitation after cloud seeding had taken place. Groundbreaking discoveries continue to be evaluated from this dataset collected in winter 2017. Multiple scientific papers have already been published,[14] with more planned for submission about the effects and benefits of cloud seeding.

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

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

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

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

Coal Facilities

Jim Bridger

Idaho Power owns one-third, or 707 MW, of the Jim Bridger coal power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility. PacifiCorp's 2021 IRP preferred portfolio includes a coal-to-gas conversion of units 1 and 2.[15] For additional details on the Jim Bridger plant, refer to Chapter 8, Planning Period Forecast. For the 2021 IRP, Idaho Power used the AURORA model's capacity expansion capability to evaluate a range of exit dates and gas conversion possibilities for the company's participation in the Jim Bridger units.

North Valmy

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

Natural Gas Facilities and Diesel Units

Bennett Mountain

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

Danskin

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

Langley Gulch

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

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

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

Diesel

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

Solar Facilities

Solar End-of-Feeder Project

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

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

Customer Generation Service

Idaho Power’s on-site generation and net metering services allow customers to generate power on their property and connect to Idaho Power’s system. For participating customers, the energy generated is first consumed on the property itself, while excess energy flows on to the company’s grid. Most customer generators use solar PV systems. As of March 31, 2021, there were 7,354 solar PV systems interconnected through the company's customer generation tariffs with a total capacity of 65.163 MW. At that time, the company had received completed applications for an additional 720 solar PV systems, representing an incremental capacity of 23.431 MW. For further details regarding customer-owned generation resources interconnected through the company's on-site generation and net metering services, see tables 4.3 and 4.4.

Table 4.3 Customer generation service customer count as of March 31, 2021

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

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

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

Oregon Solar Photovoltaic Pilot Program

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

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

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

Public Utility Regulatory Policies Act

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

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

As of July 1, 2021, Idaho Power had 131 PURPA contracts with independent developers for approximately 1,140.40 MW of nameplate capacity. These PURPA contracts are for hydroelectric projects, cogeneration projects, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power generation facilities. Of the 131 contracts, 129 were online as of July 1, 2021, with a cumulative nameplate rating of approximately 1,136.6 MW. Figure 4.2 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

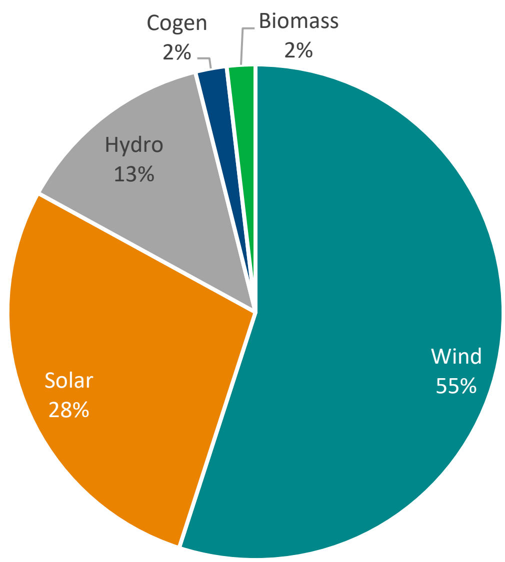

Figure 4.2 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. To account for likely variability in future PURPA resources, the 2021 IRP includes three contract renewal scenarios for existing PURPA resources: a 25% base case renewal rate and 0% and 100% low and high case bookends. Generation from PURPA contracts is forecasted early in the IRP planning process to update the accounting of supply-side resources available to meet load. The PURPA forecast used in the 2021 IRP was completed in December 2020. Details on signed PURPA contracts, including capacity and contractual delivery dates, are included in *Appendix C—Technical Report*.

Non-PURPA Power Purchase Agreements

Elkhorn Wind

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

Raft River Unit 1

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

Neal Hot Springs

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

Jackpot Solar

On March 22, 2019, Idaho Power and Jackpot Holdings, LLC, entered a 20-year PPA for the purchase and sale of 120 MW of solar electric generation from the Jackpot Solar facility to be built north of the Idaho–Nevada state line near Rogerson, Idaho. Under the terms of the PPA, Idaho Power will receive all RECs from the project. Jackpot Solar is scheduled to be online in December 2022.

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

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

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie PUD in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally, primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, with the initial exchange agreement with Idaho Power ending in 2015. At the end of the initial term, Idaho Power exercised its right to extend the agreement through 2020. At the end of the 2020 term, Idaho Power once again exercised its right to extend the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Power Market Purchases and Sales

Idaho Power relies on regional power markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power is especially dependent on the regional power market purchases during peak-load periods. The existing transmission system is used to import the power purchases. A reliance on regional power markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

Transmission MW Import Rights

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

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

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

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

IRP REPORT:

FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

5. FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

Generation Resources

Supply-side generation resources include traditional generation resources, renewable resources, and storage resources. As discussed in Chapter 6, demand-side programs are an essential and valuable component of Idaho Power's resource strategy. The following sections describe the supply-side resources and energy-storage technologies considered when Idaho Power developed and analyzed the resource portfolios for the 2021 IRP. Not all supply-side resources described in this section were included in the modeling, but every resource described was considered.

The primary source of cost information for the 2021 IRP is the 2020 Annual Technology Baseline report released by the National Renewable Energy Laboratory (NREL) in July 2020.[16] Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the recency of the information. For a full list of all the resources considered and cost information, refer to Chapter 8. All cost information presented is in nominal dollars with an online date of 2023 for all levelized cost of energy (LCOE) calculations. The levelized cost figures are based on Idaho Power's cost of capital.

Resource Contribution to Peak

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

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

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

[16] atb.nrel.gov/

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

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

Renewable Resources

Renewable energy resources serve as the foundation of Idaho Power's existing portfolio. The company emphasizes a long and successful history of prudent renewable resource development and operation, particularly related to its fleet of hydroelectric generators. In the 2021 IRP, a variety of renewable resources were included in many of the portfolios analyzed. Renewable resources are discussed in general terms in the following sections.

Hydroelectric

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

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

Small-scale hydroelectric projects have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PPAs with Idaho Power.

Solar

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

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

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

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

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

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

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

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

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

Targeted Grid Solar and Storage

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

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

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

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

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

Table 5.1 Storage capacity required to defer infrastructure investments

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

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

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

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

Geothermal

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

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

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

Wind

Modern wind turbines effectively collect and transfer energy from windy areas into electricity. A typical wind development consists of an array of wind turbines, with each turbine ranging in size from 1 to 5 MW. Most potential wind sites in southern Idaho lie between the south-central and the southeastern part of the state. Wind energy sites in areas that receive consistent, sustained winds greater than 15 miles per hour are the best candidates for development.

Upon comparison with other renewable energy alternatives, wind energy resources are well suited for the Intermountain and Pacific Northwest regions, as demonstrated by the large number of existing projects. Wind resources present operational challenges for electric utilities and system operators due to the variable nature of wind-energy generation. To adequately account for the unique characteristics of wind energy, resource planning of new wind resources requires estimates of the expected annual energy and capacity contribution. The 2021 IRP assumed an annual average capacity factor of 35% for projects sited in Idaho and 45% for projects sited in Wyoming.

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

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

Biomass

The 2021 IRP includes anaerobic digesters as a resource alternative. Multiple anaerobic digesters have been built in southern Idaho due to the size and proximity of the dairy industry and the large quantity of fuel available. Of the biomass technologies available, the 2021 IRP considers anaerobic digesters as the best fit for biomass resources within the service area.

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

Thermal Resources

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

Natural Gas Resources

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

Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial, dispatchable power generation in the region. CCCT technology benefits from a relatively low initial capital cost compared to other baseload resources; has high thermal efficiencies; is highly reliable;

provides significant operating flexibility; and when compared to coal, emits fewer emissions and requires fewer pollution controls. Modern CCCT facilities are highly efficient and can achieve efficiencies of approximately 60% (lower heating value) under ideal conditions.

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

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

Simple-Cycle Combustion Turbines

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

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

Idaho Power currently owns and operates approximately 430 MW of SCCT capacity. As peak summertime electricity demand continues to grow within Idaho Power's service area, SCCT generating resources remain a viable option to meet peak load during critical high-demand periods when the transmission system is constrained. The SCCT plants may also be dispatched based on economics during times when regional energy prices peak due to weather, fuel supply shortages, or other external grid influences.

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

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engine (RICE) generation sets are typically multi-fuel engines connected to a generator through a flywheel and coupling. They are typically capable of burning natural gas or other liquid petroleum products. They are mounted on a common base frame, resulting in the ability for an entire unit to be assembled, tuned, and tested in the factory prior to delivery to the power plant location. This production efficiency minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple identical units, allowing each engine to be operated at its highest efficiency level once started. As demand for grid generation increases, additional units can be started sequentially or simultaneously. This configuration also allows for relatively inexpensive future expansion of the plant capacity. Reciprocating engines provide unique benefits to the electrical grid. They are extremely flexible because they can provide ancillary services to the grid in just a few minutes. Engines can go from a cold start to full load in 10 minutes.

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

Combined Heat and Power

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

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

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different. While not expressly analyzed in the 2021 IRP, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company.

Coal Conversion to Natural Gas

There are two primary methods by which a coal power plant can be converted to natural gas. The less common way is to fully retire the existing coal facility and replace it with a CCCT natural gas facility. The more common method is to convert the existing steam boiler to utilize natural gas instead of coal.[19] In either case, the conversion process can create numerous benefits, including reduced emissions, reduced plant O&M expenses, reduced capital costs, and increased flexibility.

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

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

Hydrogen Retrofit Opportunities

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

Nuclear Resources

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

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

For the 2021 IRP, a 77-MW SMR was analyzed. Compared to typical reactor designs, SMRs offer numerous benefits, including smaller physical footprints, reduced capital investment, plant size scalability, and greatly enhanced flexibility. Although current operating parameters are not available, Idaho Power has modeled the operational characteristics of an SMR plant similar to a combined cycle plant. Grid services provided by the SMR include baseload energy, peaking capacity, and flexible capacity.

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

Coal Resources

Conventional coal generation resources have been part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over emissions and climate change coupled with historic-low natural gas prices have made it imprudent to consider building new conventional coal generation resources.

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

Storage Resources

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

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

Energy storage can provide numerous grid services in both short (less than 1 hour) and medium duration (between 1 hour and 8 hours). Short-term services include ancillary services like frequency regulation, spinning reserve, and reactive power support. In the medium duration, storage today can provide peak shaving, arbitrage, transmission and distribution deferral, and shaping for VERs.

Battery Storage

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

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

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

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

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

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

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

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

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

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

Pumped-Hydro Storage

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

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

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

IDAHO POWER
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IRP REPORT:

DEMAND-SIDE RESOURCES

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

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

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

Energy Efficiency Forecasting—Energy Efficiency Potential Assessment

For the 2021 IRP, Idaho Power's third-party contractor, Applied Energy Group (AEG), provided a 20-year forecast of Idaho Power's energy efficiency potential from a utility cost test (UCT) perspective. The contractor also provided additional bundles of energy efficiency and their associated costs beyond the achievable economic potential for analysis in the 2021 IRP.

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

1. *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures

regardless of cost. In new construction, customers and developers are assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every applicable measure available. The retrofit measures are phased in over several years, which is increased for higher-cost measures.

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

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

Energy Efficiency Modeling

In addition to the baseline energy efficiency potential study that assessed technical, economic, and achievable potential in a manner consistent with past IRPs, the company modeled extra bundles of achievable technical energy efficiency and their costs in the AURORA model in the 2021 IRP.

Technically Achievable Supply Curve Bundling

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

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

After bundle creation, the bundles were loaded into the AURORA software with a 'nameplate' capacity (peak kW) and an 8,760-hour load shape that contained the percentage of peak demand for each hour of the year. A levelized cost was given for each bundle for each year. Because energy efficiency bundles may be necessary at different times, each bundle was modeled as its own resource for every year of the planning period. This gave the model the ability to select energy efficiency at any point in the planning period and keep the energy efficiency program active for as long as necessary. Therefore, the energy efficiency bundles were evaluated for every year in the model and activated or deactivated accordingly. If more than one year of a bundle is selected, the values are additive. For example, if the summer low-cost bundle is selected in 2023 at 3.6 MW and it is selected again in 2024, but is no longer needed in 2025, that bundle contributes 3.6 MW in 2023 and 7.2 MW in 2024 continuing through the remainder of the planning period. Once a bundle is selected, its contribution was held in the model throughout the remainder of the 20-year period. Table 6.1 lists the average annual resource potential and average levelized cost for the bundles.

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

Bundle	20-Year Average Annual Potential (aMW)	20-Year Average Real Cost ($/MWh)
Summer Low Cost	3.6	$103
Summer High Cost	21.7	$596
Winter Low Cost	12.6	$66
Winter High Cost	5.8	$325

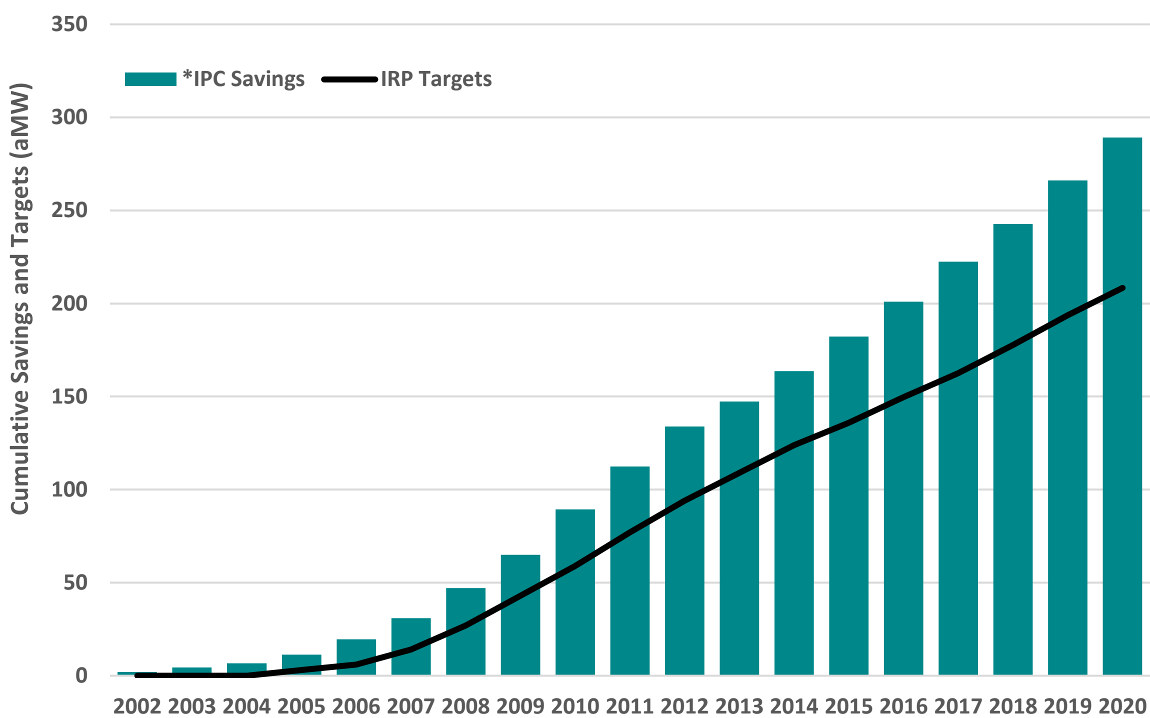
Future Energy Efficiency Potential

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

DSM Program Performance and Reliability

Energy Efficiency Performance

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



***** Idaho Power savings include Northwest Energy Efficiency Alliance non-code/federal standards savings

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

Idaho Power's energy efficiency portfolio is currently a cost-effective and low-cost resource. Table 6.2 shows the 2020 year-end program results, expenses, and corresponding benefit-cost ratios.

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

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

* Values may not add to 100% due to rounding

** NPV=Net Present Value

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

Note: Excludes market transformation program savings.

Energy Efficiency Reliability

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

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

The timing of impact evaluations is based on protocols from these industry standards, with large portfolio contributors being evaluated more often and with more rigor. Smaller portfolio contributors are evaluated less often and require less analysis as most of the program measure savings are deemed savings from the RTF or other sources. Evaluated savings are expressed through a realization rate (reported savings divided by evaluated savings). Realized savings of programs evaluated between 2019 and 2020 ranged between 97% and 100%. The savings-weighted-realized-savings average over the same period is 99%.

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is composed of three programs. Table 6.3 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2020 summer season, Irrigation Peak Rewards participants contributed 82% of the total potential demand-reduction capacity, or 298 MW. More details on Idaho Power’s demand response programs can be found in the *Demand-Side Management 2020 Annual Report*.

Table 6.3 2020 demand response program capacity

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

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

Figure 6.2 shows the historical annual demand response program capacity between 2004 and 2020. The demand-response capacity was lower in 2013 because of the one-year suspension of both the irrigation and residential programs. The temporary program suspension was due to a lack of near-term capacity deficits in the 2013 IRP.

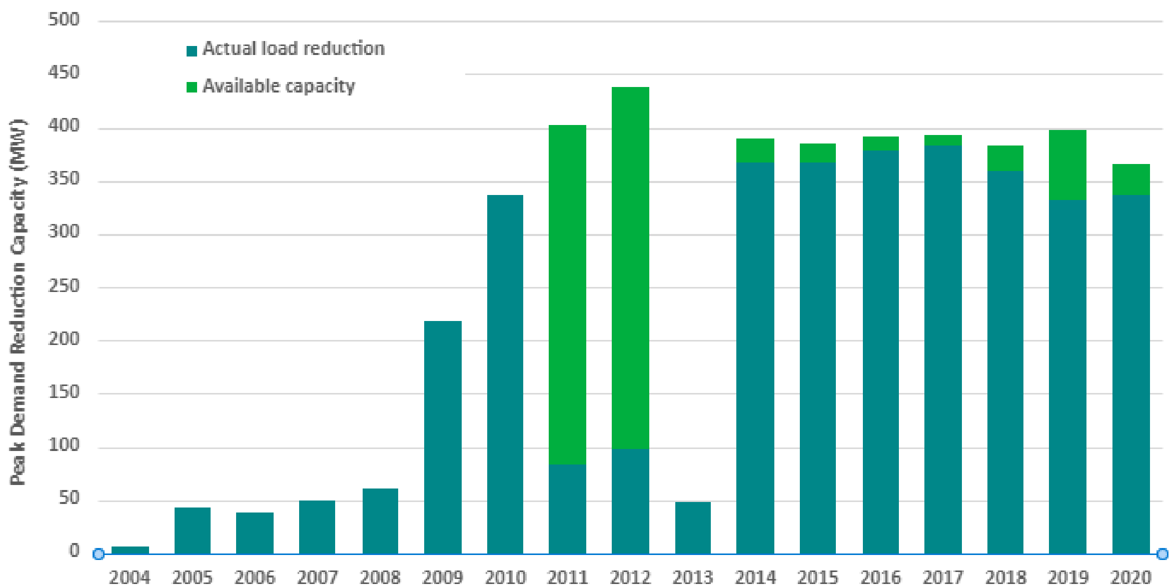


Figure 6.2 Historic annual demand response program performance

Demand Response Resource Potential

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

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

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

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

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

T&D Deferral Benefits

Energy Efficiency

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

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

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

Idaho Power calculated the corresponding T&D deferral value for each year in the 20-year forecast of incremental achievable energy efficiency. The calculated T&D deferral values ranged from $6.52 per kW-year to $1.40 per kW-year based on a forecasted incremental reduction in system sales of between 0.86% to 0.43% from energy efficiency programs. The 20-year average was $3.74 per kW-year. These values are then used in the calculation of energy efficiency cost-effectiveness.

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

Distribution System Planning

Although Idaho Power has always conducted distribution system planning (DSP), in March 2019 the OPUC initiated an investigation into distribution system planning in docket UM 2005 with the stated objective of directing electric utilities to “develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments.”[25]

Over nearly two years, OPUC staff, stakeholders, and utilities have engaged in workshops and seminars to discuss distribution system planning possibilities, best practices, and lessons learned from other jurisdictions. These efforts culminated in DSP guidelines from OPUC staff, which were subsequently adopted by the OPUC in Order 20-485 on December 23, 2020. The adopted DSP guidelines identify specific efforts that utilities must conduct, analyze, and compile into reports filed every two years. On October 15, 2021, Idaho Power filed its Distribution System Plan Part I report with the OPUC in docket UM 2196. Within the report the company identified how the DSP and resource planning processes can inform and/or impact each respective plan.

One of the clear relationships between DSP and integrated resource planning is the ability to consider avoided or deferred distribution investments as a cost offset to potential resource investments. The value of such T&D deferral will be evaluated closely in the DSP process, as well as in the company’s IRP. Distribution system planning affects the calculation of the T&D deferral value included in the IRP’s energy efficiency cost-effectiveness test and the T&D deferral value of DERs in the IRP resource stack. To the extent that IRPs identify DER in the first two to four years of the IRP Action Plan, local load forecasts and the distribution plan would be adjusted based on the anticipated peak demand reduction.

Importantly, however, there are differences between the IRP and DSP processes. The IRP analyzes several long-term peak forecast scenarios focused on long-term resource needs. The DSP, on the other hand, analyzes near-term loading scenarios that can stress the local area capacity or operating constraints that may occur at peak or light loads. Further, any DER identified in the IRP does not specify location. The DSP is needed to inform the locational value (or cost) of DER on Idaho Power’s system. With these considerations, the IRP and DSP are linked, and the results of either informs the other in an iterative process.

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

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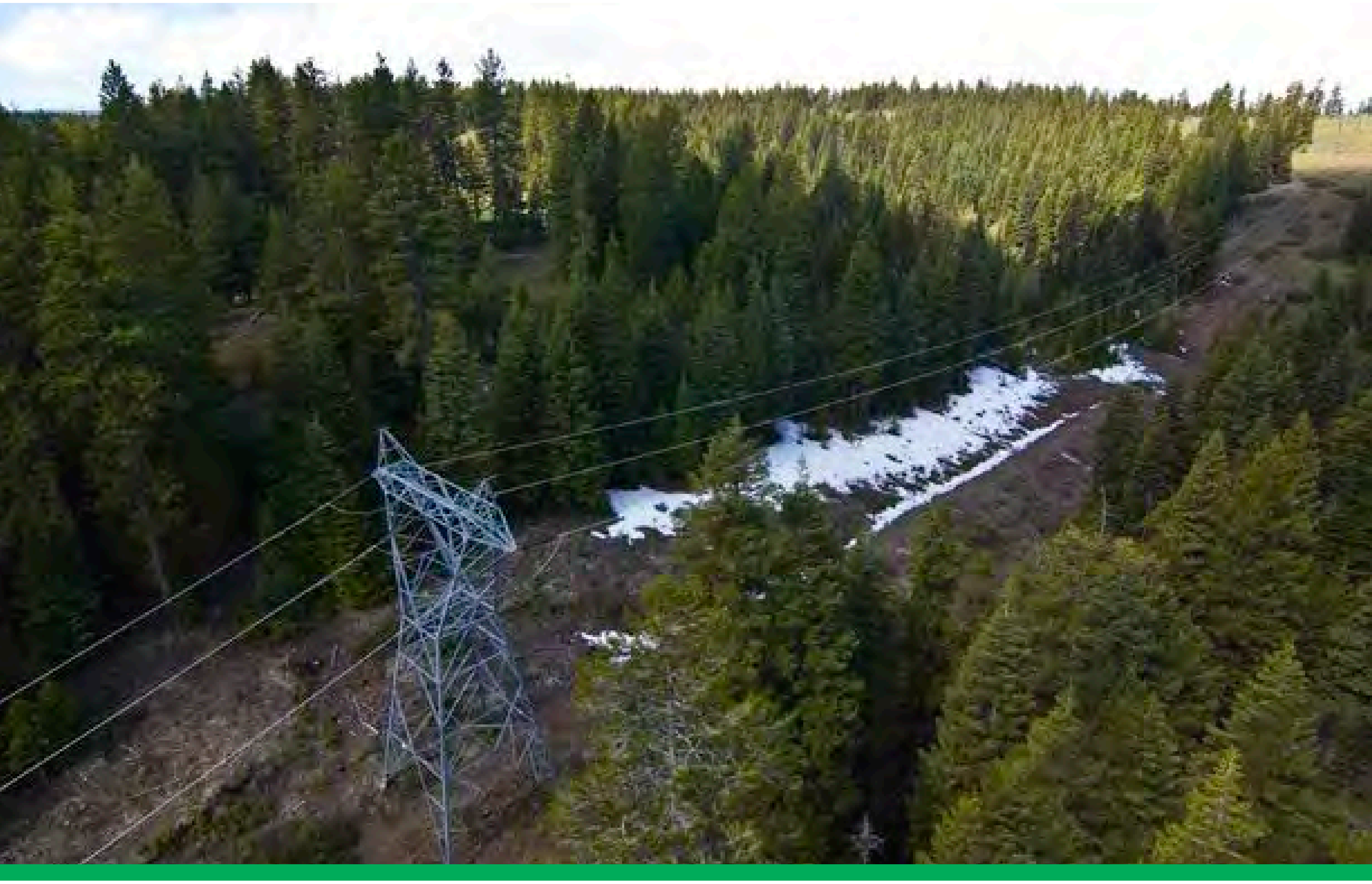

IRP REPORT:

TRANSMISSION PLANNING

7. TRANSMISSION PLANNING

Past and Present Transmission

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

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

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

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

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

Transmission Planning Process

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

Local Transmission Planning

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

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

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

Regional Transmission Planning

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

NorthernGrid membership includes Avista, Berkshire Hathaway Energy Canada, BPA, Chelan County PUD, Grant County PUD, Idaho Power, NorthWestern Energy, PacifiCorp (Rocky Mountain Power and Pacific Power), Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. Biennially, NorthernGrid will develop a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, local transmission plans, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers. The 2020–2021 regional transmission plan was published in December 2021 and can be found on the NorthernGrid website: www.northerngrid.net.

Existing Transmission System

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

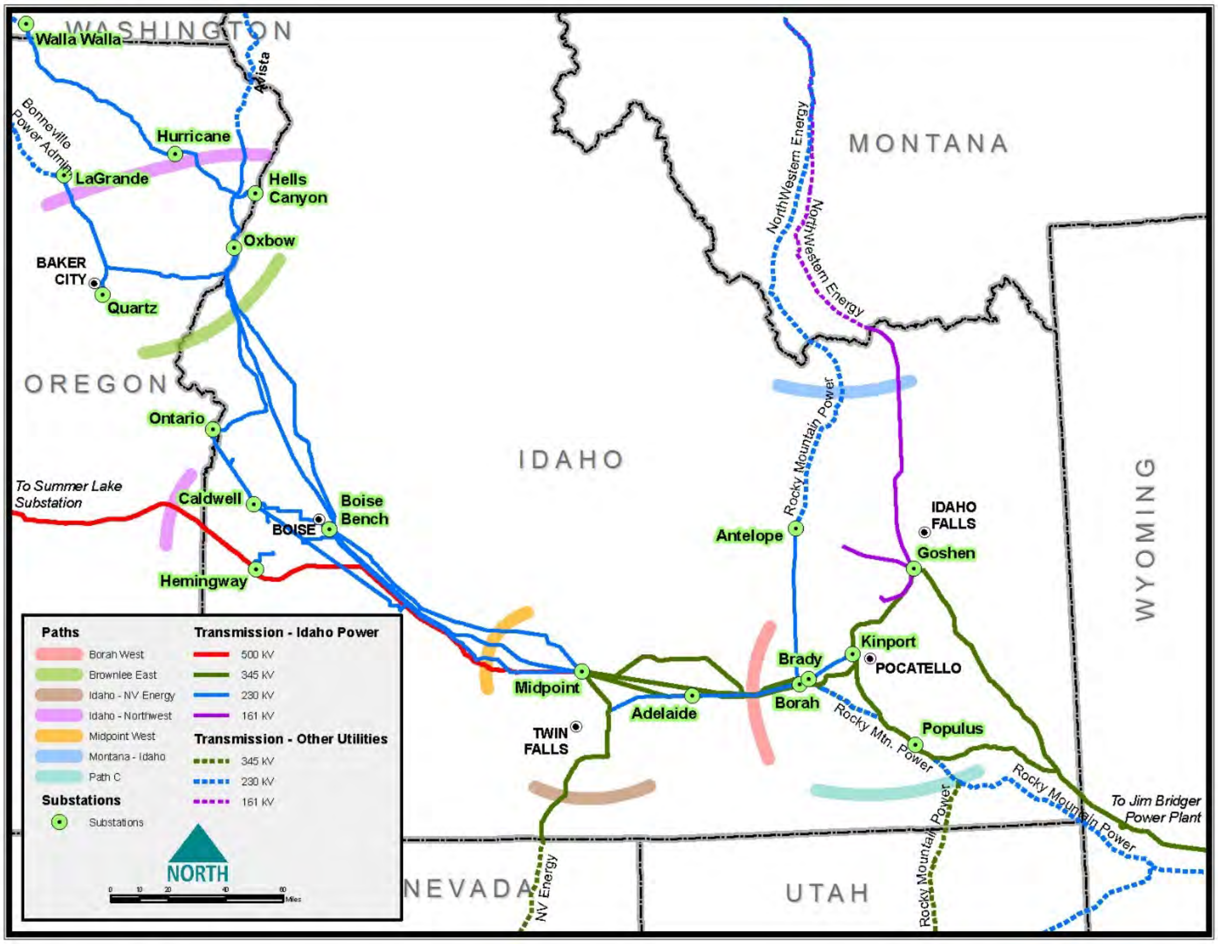

Figure 7.1 Idaho Power transmission system map

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

Idaho to Northwest Path

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

Operationally since 2020, Idaho Power has seen increased third-party demand for west-to-east or north-to-south firm transmission from the Pacific Northwest to the desert southwest or California. Idaho Power continues to reserve capacity on internally controlled lines for facilitating external market purchases, but with the increased demand for firm transmission, the company has experienced near-term difficulty in reserving transmission on third-party controlled transmission between the Mid-C market hub and the Idaho to Northwest path. The company has made efforts to reserve transmission capacity on third-party systems since the 2019 IRP (further discussed in *Appendix D*).

Brownlee East Path

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

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

Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy south from Montana into Idaho. In the north to south direction, Idaho Power has 167 MW of capacity on the path.

Borah West Path

The Borah West transmission path is internal to Idaho Power's system and is jointly owned between Idaho Power and PacifiCorp. Idaho Power owns 1,467 MW of the path, and PacifiCorp owns 1,090 MW of the path. The path includes 345-kV, 230-kV, and 138-kV transmission lines west of the Borah Substation located near American Falls, Idaho. Idaho Power's one-third share of energy from the Jim Bridger plant flows over this path, as well as energy from east-side resources and imports from Montana, Wyoming, and Utah. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production move west across the system to the Pacific Northwest. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Borah West path.

Midpoint West Path

The Midpoint West transmission path is internal to Idaho Power's system and is a jointly owned path between Idaho Power and PacifiCorp. Idaho Power owns 1,710 MW of the path, and PacifiCorp owns 1,090 MW of the path (all on the Midpoint–Hemingway 500-kV line). The path is composed of 500-kV, 230-kV, and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. Like the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

Idaho–Nevada Path

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

Idaho–Wyoming Path

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

Idaho–Utah Path

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

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

Table 7.1 Transmission import capacity

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

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

Boardman to Hemingway

In the 2006 IRP, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a 230-kV line interconnecting at the McNary Substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including evaluating upgrade options of existing transmission lines, evaluating terminus locations, and sizing the project to economically meet the needs of Idaho Power and other regional participants. The project, identified in 2006, has evolved into what is now B2H. The project, which is expected to provide a total of 2,050 MW of bidirectional capacity[26], involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn substation near Boardman, Oregon, and the existing Hemingway *s*ubstation in southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to economically serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and resiliency
- Reduced capacity limitations on the regional transmission system as demands on the system continue to grow
- Flexibility to integrate renewable resources and more efficiently implement advanced market tools, such as the EIM

[26] B2H is expected to provide 1,050 MW of capacity in the West-to-East direction, and 1,000 MW of capacity in the East-to-West direction.

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

The B2H project has been identified as a preferred resource in IRPs since 2009 and ongoing permitting activities have been acknowledged in every IRP near-term Action Plan since 2009. The 2017 IRP was the first IRP to include construction activities in the near-term Action Plan and the 2019 IRP also included construction activities in the near-term Action Plan. The 2017 IRP and 2019 IRP near-term Action Plans, including B2H construction related activities mentioned within, were acknowledged by both the Idaho and Oregon PUCs.

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

B2H is a regionally significant project; it was identified as a key transmission component of each Northern Tier Transmission Group biennial regional transmission plan for ten years 2010–2019. The B2H project is similarly a major component of the 2020–2021 NorthernGrid regional transmission plan, published in December 2021. Regional transmission planning efforts are widely regarded as producing efficient and cost-effective pathways to meet the load and resource needs of a given region.

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

B2H Value

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

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

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

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

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

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

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

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

Project Participants

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

Table 7.2 B2H capacity and permitting cost allocation

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

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

Table 7.3 B2H capacity allocation

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

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

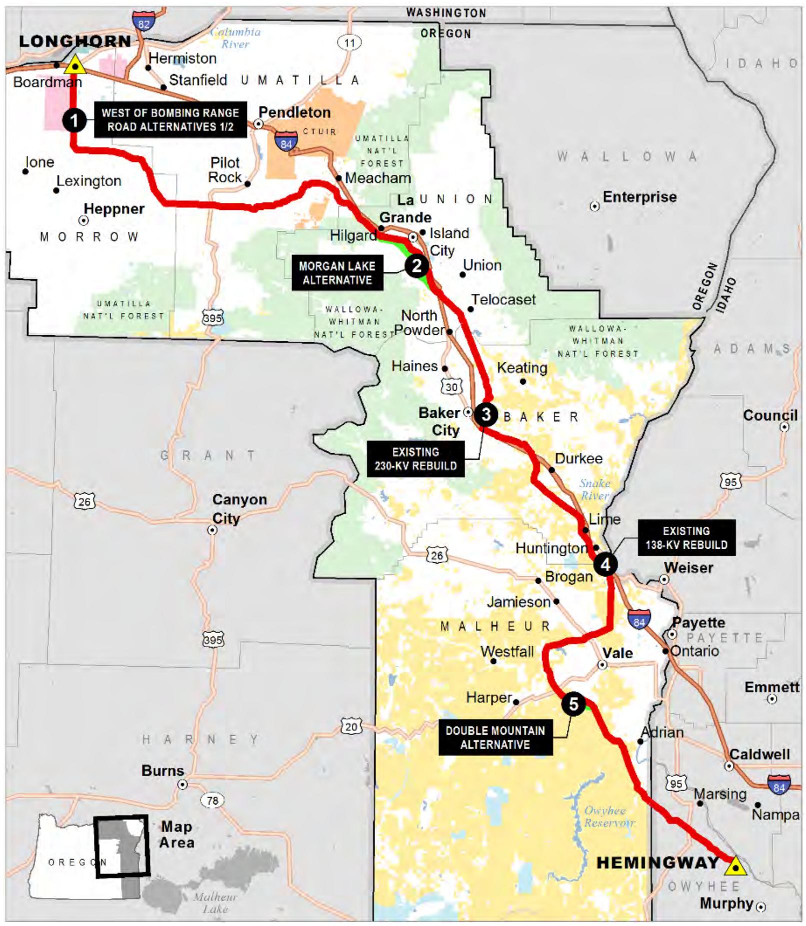

Figure 7.2 B2H route submitted in 2017 Oregon Energy Facility Siting Council (EFSC) Application for Site Certificate

Permitting Update

Permitting of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), United States Forest Service (USFS), United States Navy, and the Energy Facilities Siting Council of Oregon (EFSC). The federal permitting process is dictated primarily by the *Federal Land Policy Management Act and National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On November 25, 2016, BLM published the

Final EIS, and the BLM issued a Record of Decision (ROD) on November 17, 2017, approving a right-of-way grant for the project on BLM-administered lands.

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

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

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

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to EFSC in February 2013 and submitted an amended pASC in summer 2017. The amended pASC was deemed complete by ODOE in September 2018. The ODOE reviewed Idaho Power's application for compliance with EFSC siting standards and released a Draft Proposed Order (DPO) for B2H on May 22, 2019. Public comment on the DPO findings were taken by ODOE and EFSC, and—based on those comments—ODOE issued a Proposed Order on July 2, 2020. A contested case on the Proposed Order has been initiated and is being presided over by an EFSC-appointed Administrative Law Judge. Idaho Power currently expects the EFSC to issue a final order and site certificate in the second half of 2022. Permitting in Idaho will consist of a Conditional Use Permit issued by Owyhee County.

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

Next Steps

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

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

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

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

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

B2H Cost Treatment and Modeling in the IRP

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. Transmission wheeling revenues, however, are not included in AURORA calculations. To remedy this inconsistency, in the 2019 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios. In the 2021 IRP, Idaho Power continued to model expected incremental third-party wheeling revenues as a reduction in costs ultimately benefitting retail customers.

Idaho Power's transmission assets are funded by native load customers, network customers, and point-to-point transmission wheeling customers based on a ratio of each party's usage of the transmission system. For the 2021 IRP, Idaho Power modeled B2H assuming the company has a 45% ownership interest and is providing transmission service to BPA, with BPA transmission wheeling payments acting as a cost-offset to the overall B2H project costs. Additionally, portfolios involving B2H result in a higher FERC transmission rate than portfolios without B2H. Although B2H provides significant incremental capacity, and will likely result in increased transmission sales, Idaho Power assumed flat transmission sales volume as a conservative assumption (other than increased volumes associated with transmission network customers such as BPA). The flat sales volume, applied to the higher FERC transmission rate, results in an additional cost offset for IRP portfolios with B2H.

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

Gateway West

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

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

In its 2017 IRP, PacifiCorp announced plans to construct a portion of the Gateway West Transmission Line in Wyoming. PacifiCorp has subsequently constructed the 140-mile segment between the Aeolus substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming. The Aeolus to Anticline 500-kV line segment was energized November 2020.

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

Figure 7.3 Gateway West map

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

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

The completed Gateway West project would provide a total of 3,000 MW of additional transfer capacity. As detailed previously, Idaho Power has a one-third interest in the capacity additions between Midpoint and Hemingway. Along with the B2H project, Gateway West is a major component of the 2020–2021 NorthernGrid regional transmission plan. The Gateway West and B2H projects are complementary and will provide upgraded transmission paths from the Pacific Northwest across Idaho and into eastern Wyoming. Regional transmission plans produce a more efficient or cost-effective plan for meeting the transmission requirements associated with the load and resource needs of the regional footprint.

Gateway West Cost Treatment and Modeling in the 2021 IRP

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

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

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

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

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

Nevada Transmission without North Valmy

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

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

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

Southwest Intertie Transmission Project-North

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

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

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

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

Figure 7.4 SWIP-North Preliminary Route

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. Supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 7.4. The company assumed all resources

Transmission lines under construction at the Hemingway substation.

were located east of the Treasure Valley. Backbone transmission assumptions include an assignment of the pro-rata share for transmission upgrades identified for resources east of Boise.

Table 7.4 Transmission assumptions and requirements

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

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IRP REPORT:

PLANNING PERIOD FORECASTS

8. 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 2021 IRP. A more detailed discussion on these topics is included in *Appendix A—Sales and Load Forecast*.

Load Forecast

Each year, Idaho Power prepares a forecast of sales and demand of electricity using the company's electrical T&D network. This forecast is a product of historical system data and trends in electricity usage along with numerous external economic and demographic factors.

Idaho Power has its annual peak demand in the summer, with peak loads driven by irrigation pumps and air conditioning (A/C) in June, July, and August. Historically, Idaho Power's growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. Both measures are important in planning future resources and are part of the load forecast prepared for the 2021 IRP.

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

The anticipated forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*.
For example, the anticipated annual average system load growth of 1.4% (over the period 2021 through 2040) comprises a residential load growth of 0.8%, a commercial load growth of 0.9%,

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

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

Significant factors that influenced the outcome of the 2021 IRP load forecast include, but are not limited to, the following items:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. In the anticipated case load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Probabilistic variations of weather are also analyzed.
- The economic forecast used for the 2021 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service-area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. The state of Idaho had the highest residential population growth rate of any state in the United States over the past five years (ending 2020).
- Conservation impacts—including DSM energy efficiency programs, codes, and standards, and other naturally occurring efficiencies—are integrated into the sales forecast. These impacts are expected to continue to erode use per customer over much of the forecast period. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., demand response is treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*. Additional impacts from on-site generation customers and electric vehicles are included as well.
- Although interest from large customers has been robust, there is some uncertainty associated with these industrial and special contract customers due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an uncertain magnitude of the energy and peak-demand requirements. The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment and/or

interest indicating a commitment of the highest probability of locating in the service area. The large number of businesses that have indicated some interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the anticipated-case sales and load forecast.

- The electricity price forecast used to prepare the sales and load forecast in the 2021 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP Preferred Portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price forecast yields lower future prices. The retail prices are mostly lower throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.
- As discussed above, the response to the novel coronavirus influenced electric usage behavior across the major rate classes. These impacts tended to balance one another; e.g., increased residential consumption due to work-from-home behavior was offset by decreased use from office and other commercial facilities. While these impacts continue to play out in decreasing importance, the impact on the long-term forecast horizon is inconsequential.

Weather Effects

The anticipated load forecast assumes average temperatures and precipitation over a 30-year meteorological measurement period, or normal climatology. This implies a 50% chance loads will be higher or lower than the anticipated load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation. Since actual loads can vary significantly depending on weather conditions, additional scenarios for an increased load requirement were analyzed to address load variability due to abnormal weather—the 70th- and 90th-percentile load forecasts. Seventieth-percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth-percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

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

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

Economic Effects

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

The state of Idaho had the highest population growth rate of any state in the United States over the past five years (ending 2020). The number of households in Idaho is projected to grow at an annual rate of 2% during the forecast period, with most of the population growth centered on the Boise City–Nampa MSA. The Boise MSA (or the Treasure Valley) encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. The number of households in the Boise–Nampa MSA is projected to grow faster than the state of Idaho, at an annual rate of 2.6% during the forecast period. In addition to the number of households, incomes, employment, economic output, and electricity prices are economic components used to develop load projections.

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

The 2021 IRP average annual system load forecast reflects continued improvement in the service-area's economy. The improving economic and demographic variables driving the 2021 forecast are reflected by a positive sales outlook throughout the planning period.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 8.1 and Table 8.1 show the results of the three forecasts used in the 2021 IRP as annual system load growth over the planning period. There is an approximately 50% probability Idaho Power's load will exceed the expected-case forecast, a 30% probability of load exceeding the 70th-percentile forecast, and a 10% probability of load exceeding the 90th-percentile forecast. The projected 20-year compound annual growth rate in the expected case forecast and 70th-percentile forecast is 1.4% during the 2021 through 2040 period. The projected 20-year average compound annual growth rate in the 90th percentile forecast is 1.4% over the 2021 through 2040 period.

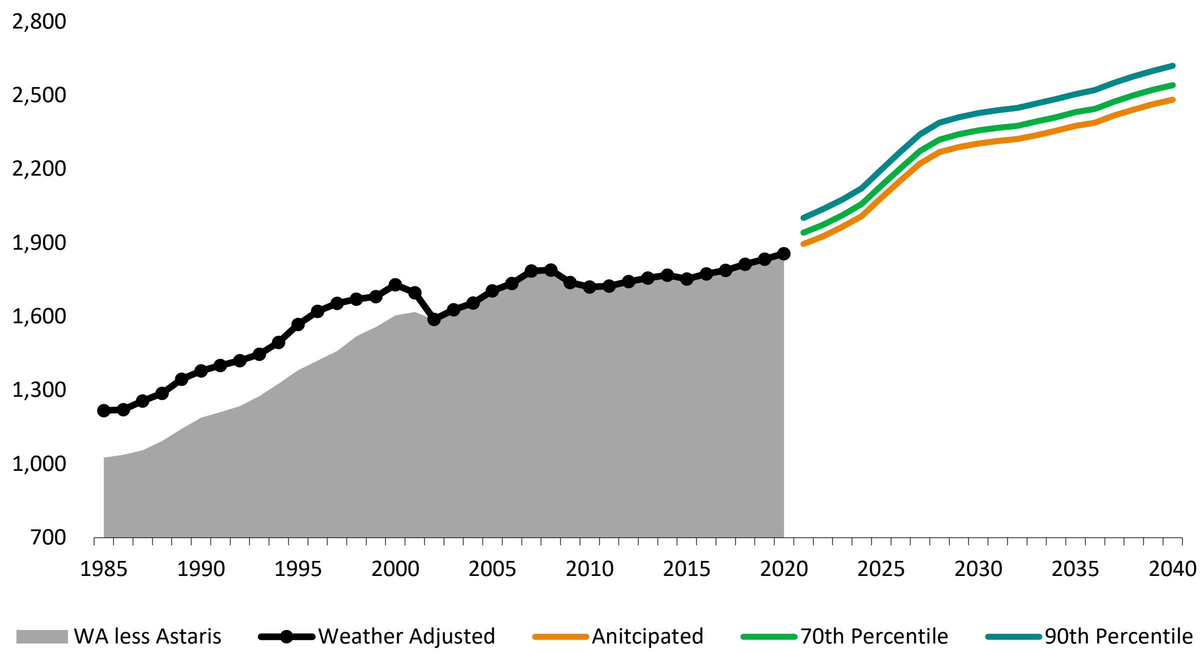

Figure 8.1 Average monthly load-growth forecast (aMW)

Table 8.1 Load forecast—average monthly energy (aMW)

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

Peak-Hour Load Forecast

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

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

Idaho Power's system peak-hour load record—3,751 MW—was recorded on Wednesday, June 30, 2021, at 7 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011—the consequences of a severe recession that brought home and business construction to a standstill. Demand response programs have also been effective at reducing peak demand in the summer. The 2021 IRP load forecast projects annual peak-hour load to grow by approximately 55 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance and are treated similarly to a supply-side resource.

Idaho Power's winter peak-hour load record is 2,527 MW, recorded January 6, 2017, at 9 a.m., matching the previous record peak December 10, 2009, at 8 a.m. Historical winter peak-hour load is much more variable than summer peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

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

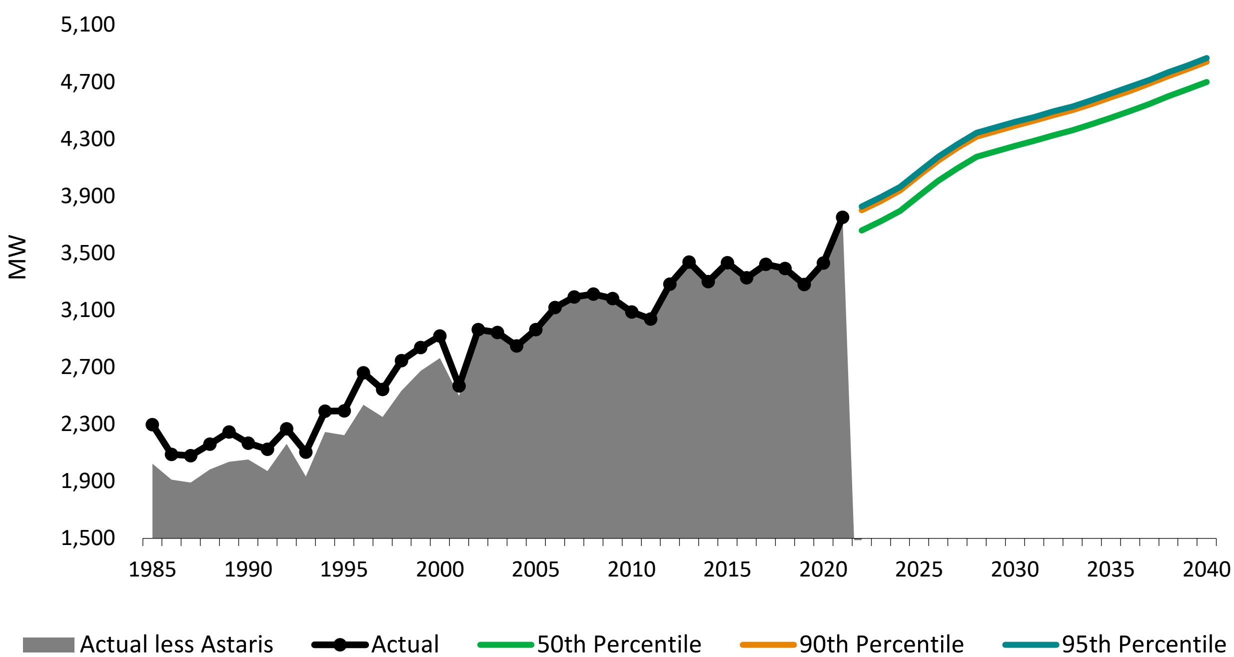

Figure 8.2 Peak-hour load-growth forecast (MW)

Table 8.2 Load forecast—peak hour (MW)

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

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

Additional Firm Load

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

Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL, and an anticipated new special contract customer. These special-contract customers comprise the entire forecast category labeled additional firm load.

Micron Technology

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

Simplot Fertilizer

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

INL

INL is one of the United States Department of Energy's (DOE) national laboratories and is the nation's lead laboratory for nuclear energy research, development, and demonstration. The DOE, in partnership with its contractors, is focused on performing research and development in energy programs and national defense. Much of the work to achieve this mission at INL is performed in government-owned and leased buildings on the Research and Education Campus in Idaho Falls, Idaho, and on the INL site, approximately 50 miles west of Idaho Falls. INL is a critical economic driver and important asset to the state of Idaho. It is the fifth-largest employer in the state of Idaho with an estimated 4,225 employees.

Anticipated Large Load Growth

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

Generation Forecast for Existing Resources

Hydroelectric Resources


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

For the 2021 IRP, Idaho Power continues the practice of using 50th-percentile future streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 50th-percentile means basin streamflows are expected to exceed the planning criteria 50% of the time and are expected to be worse than the planning criteria 50% of the time.

Idaho Power uses two modeling methods to develop future flows for the IRP. The first method is for accounting for surface water regulation in the system, this consists of two models built in the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES) RiverWare modeling framework collectively referred to as the "Planning Models." The first of these models covers the spatial extent of the Snake River Basin from the headwaters to Brownlee Reservoir inflow. The second model takes the results of the first and regulates the flows through the HCC. The second method uses the Enhanced Snake Plain Aquifer Model (ESPAM) to model aquifer management practices implemented on the ESPA. Modeling for the 2021 IRP used version 2.1 of the ESPAM model. The two modeling methods used in combination produce a normalized hydrologic record for the Snake River Basin from water year 1951 through 2018.
The record is normalized to account for specified conditions relating to Snake River reach gains, water management facilities, irrigation facilities, and operations. The 50th percentile modeled streamflows are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2021 IRP is included in *Appendix C—Technical Report*.

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

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

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

A representative measure of the streamflow condition is the annual inflow volume to Brownlee Reservoir. Figure 8.3 shows historical annual Brownlee inflow volume as well as modeled Brownlee inflow distributions for each year of the 2021 IRP. The 2019 IRP modeling results for the 50th, 70th, and 90th percentiles are shown for reference only to benchmark the changes in hydrogeneration modeling between IRP cycles. As Figure 8.3 shows, the 2021 hydrogeneration distributions are very similar to the 2019 hydrogeneration results. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The modeled inflows include reductions related to declining base flows in the Snake River and projected future management practices. As noted previously in this section, these declines are assumed to continue through the planning period.

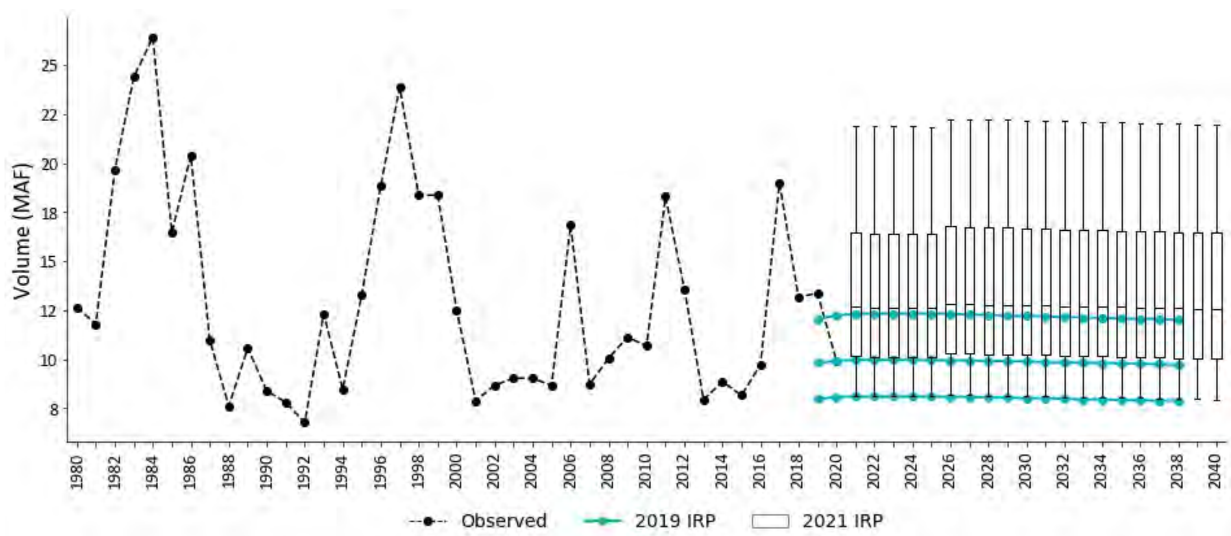

Figure 8.3 Brownlee inflow volume historical and modeled percentiles

Coal Resources

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

Jim Bridger

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

For the 2021 IRP, Idaho Power used AURORA's LTCE model to determine the best Bridger operating option specific to Idaho Power's system subject to the following constraints:

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

Costs associated with continued capital investments and early exit or conversion were included in the analysis. If the units were converted to natural gas, changes to the fuel costs and operating expenses were modeled to accurately capture the change in fuel. For those scenarios where units 1 and 2 convert to natural gas, they are assumed to operate through their useful life and are exited in 2034.

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

North Valmy

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

Natural Gas Resources

Idaho Power owns and operates four natural gas SCCTs and one natural gas CCCT, having combined nameplate capacity of 762 MW. The SCCT units are typically operated during peak-load events in the summer and winter. Idaho Power's CCCT, Langley Gulch, is typically dispatched more frequently and for longer runtimes than the SCCTs because of the higher efficiency rating of a CCCT. The company plans to continue to operate each of its existing gas units through the 20-year planning horizon. Idaho Power is monitoring alternative fuels, such as hydrogen, or hydrogen/natural-gas fuel blends for potential use in the future at existing natural gas plants.

Natural Gas Price Forecast

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

Table 8.3 Utility peer natural gas price forecast methodology

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

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

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

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

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

The following industry events helped inform the third-party 2021 natural gas price forecast used in the IRP analysis:

- Status of North American major gas basins (Figure 8.4) and pipeline capacity
- Oil prices and the associated gas production
- New and existing natural gas electric generation and the possible replacement of coal and nuclear capacity retirements

- Changes to residential and commercial customer gas demand from energy efficiency gains as well as policy changes that include new gas appliance service bans
- Global competition from gas producers such as Russia and Qatar and the role of liquefied natural gas exports
- Possible policy changes at the federal level included carbon price and societal cost inclusion to natural gas as well as other wider energy policy developments

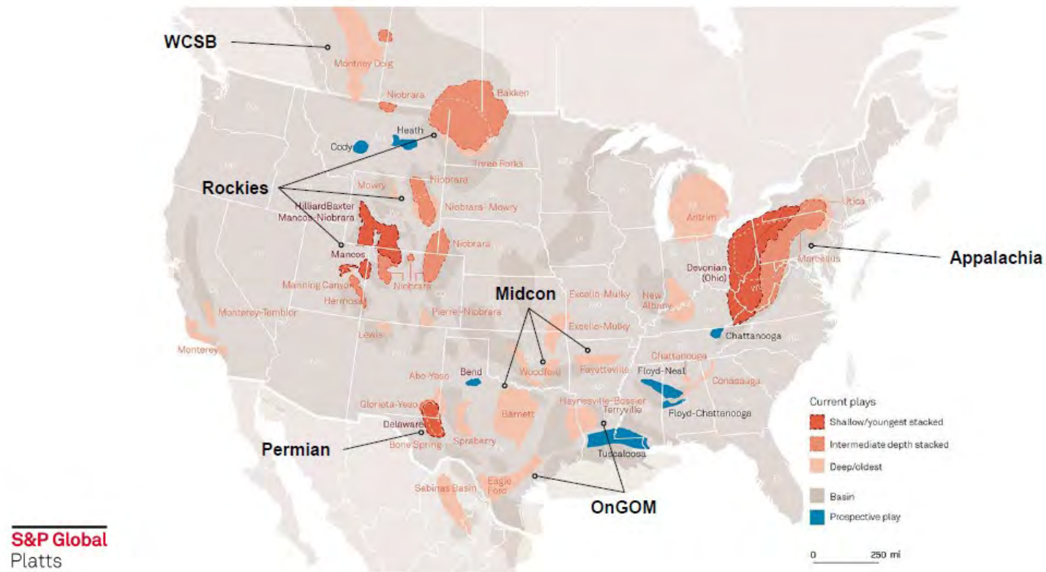

Figure 8.4 North American major gas basins

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

Platts' 2021 Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington, served as the planning case forecast of fueling costs for existing and potential new natural gas generation on the Idaho Power system. Sumas is where most of the fuel for Idaho Power's natural gas generation comes from.

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

Natural Gas Transport

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

Idaho Power projects that require additional natural gas generating capacity beyond an incremental 600 MW of capacity would require an expansion of Northwest Pipeline from the Rocky Mountain supply region to Idaho. The 600 MW limit, beyond which pipeline expansion is required, is derived from Northwest Pipeline's estimation of expected turnback capacity from Stanfield, Oregon, to Idaho as presented in Northwest Pipeline's fall 2019 Customer Advisory Board meeting. Besides the uncertainty of acquiring capacity on existing pipeline beyond that necessary for 600 MW of incremental natural gas generating capacity, a pipeline expansion would provide diversification benefits from the current mix of firm transportation composed of 60% from British Columbia, 40% from Alberta, and no firm capacity from the Rocky Mountain supply region. In response to a request for a cost estimate for a pipeline expansion from the Rocky Mountain supply region, Northwest Pipeline calculated a levelized cost for a 30-year contract of $1.39/Million British Thermal Units (MMBtu) per day. Idaho Power applied this rate to potential natural gas generation types with an assumption of high-capacity factor (100% capacity coverage), medium capacity factor (33%), and low-capacity factor (25%). For the medium- and low-capacity factor plants, it is assumed that transportation would be procured in the short-term capacity release market, or through delivered supply transactions to cover 100% of the requirements on any given day.

Analysis of IRP Resources

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

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

ability to provide flexible capacity, the system attributes analyzed include the ability to provide dispatchable peaking capacity, non-dispatchable (i.e., coincidental) peaking capacity, and energy. Importantly, energy in this analysis is considered to include not only baseload-type resources but also resources, such as wind and solar, that provide relatively predictable output when averaged over long periods (i.e., monthly, or longer). The resource attribute analysis also designates those resources whose variable production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are shown using two cost metrics: levelized cost of capacity (fixed) (LCOC) and LCOE. These metrics are discussed later in this section. Resources are evaluated from a TRC perspective. Idaho Power recognizes the TRC is not in all cases the realized cost to the company. Examples for which the TRC is not the realized cost include energy efficiency resources where the company incentivizes customer investment, and supply-side resources whose production is purchased under long-term contract (e.g., PPA and PURPA). Nevertheless, Idaho Power views the evaluation of resource options using the TRC as allowing a like-versus-like comparison between resources, and consequently is in the best interest of our customers.

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

The levelized costs for the various resource alternatives analyzed include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs of resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, plant construction costs, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an AFUDC (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio in AURORA. Net levelized costing for the bundled energy efficiency resource options modeled in the IRP are provided in Chapter 5. The net levelized costs for energy efficiency resource options include annual program administrative and marketing costs, an annual incentive, and annual participant costs.

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

LCOC—IRP Resources

The annual fixed revenue requirements in nominal dollars for each resource are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month. Included in these LCOCs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic lives, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life.

The expression of these costs in terms of kW of *peaking* capacity can have significant effect, particularly for VERs (e.g., wind) having peaking capacity significantly less than installed capacity. The LCOC values for the potential IRP resources are provided in Figure 8.5.

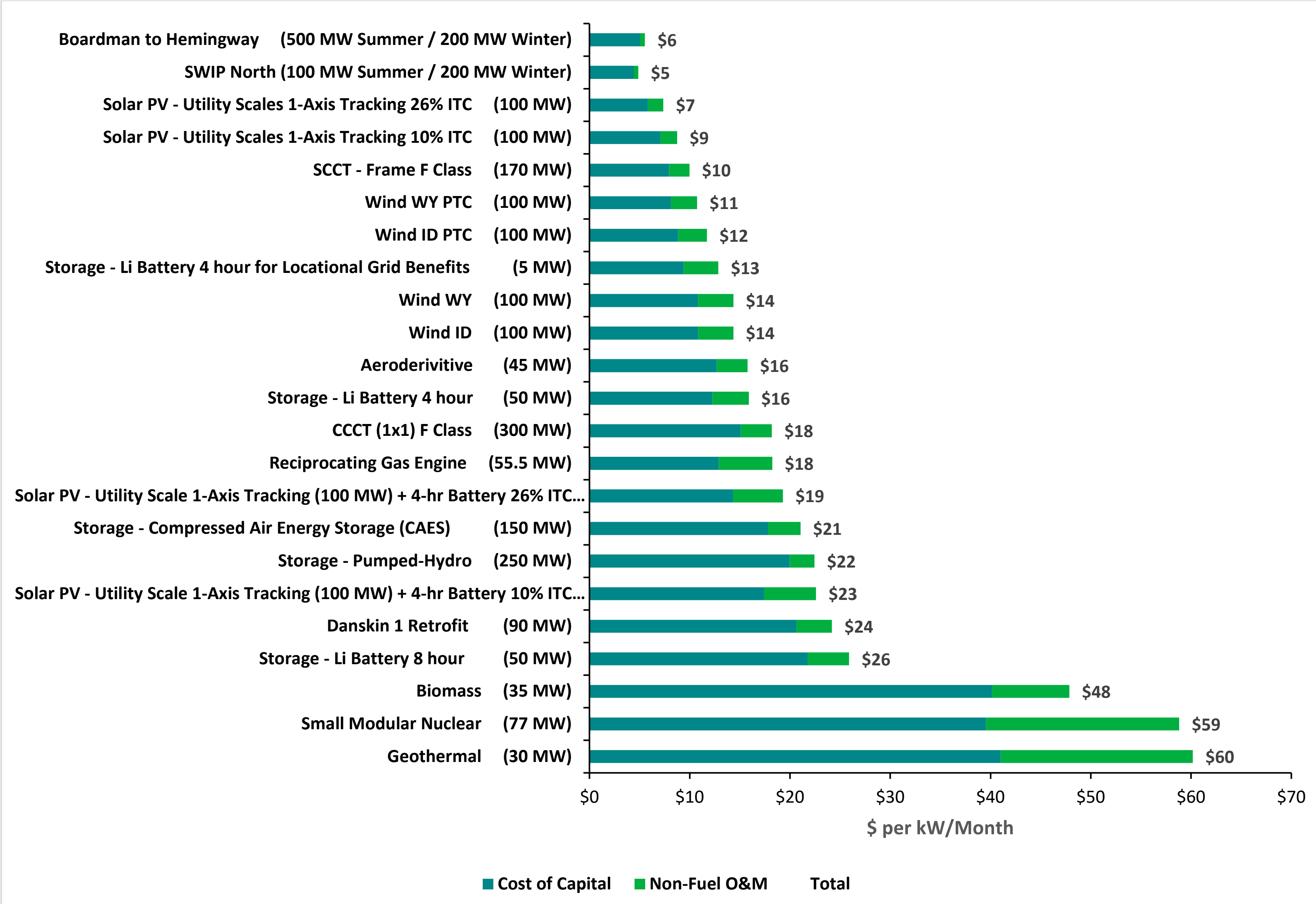

Figure 8.5 Levelized capacity (fixed) costs in millions of 2021 dollars per kW per month[29]

LCOE—IRP Resources

Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low (or zero) operating costs. The LCOE metric represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource. The nominal LCOE assuming the expected capacity factors for each resource is shown in Figure 8.6. Included in these costs are the capital cost, non-fuel O&M, and fuel costs. The cost of recharge energy for storage resources and wholesale energy for B2H are not included in the graphed LCOE values.

The LCOE is provided assuming a common online date of 2021 for all resources and based on Idaho Power specific financing assumptions. Idaho Power urges caution when comparing LCOE values between different entities or publications because the valuation is dependent on several underlying assumptions. The LCOE graphs also illustrate the effect of the Investment Tax Credit on solar-based energy resources, including coupled solar-battery systems. Idaho Power emphasizes that the LCOE is provided for informational purposes and is essentially a convenient summary metric reflecting the approximate cost competitiveness of different generating technologies. However, the LCOE is not an input into AURORA modeling performed for the IRP.

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

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

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

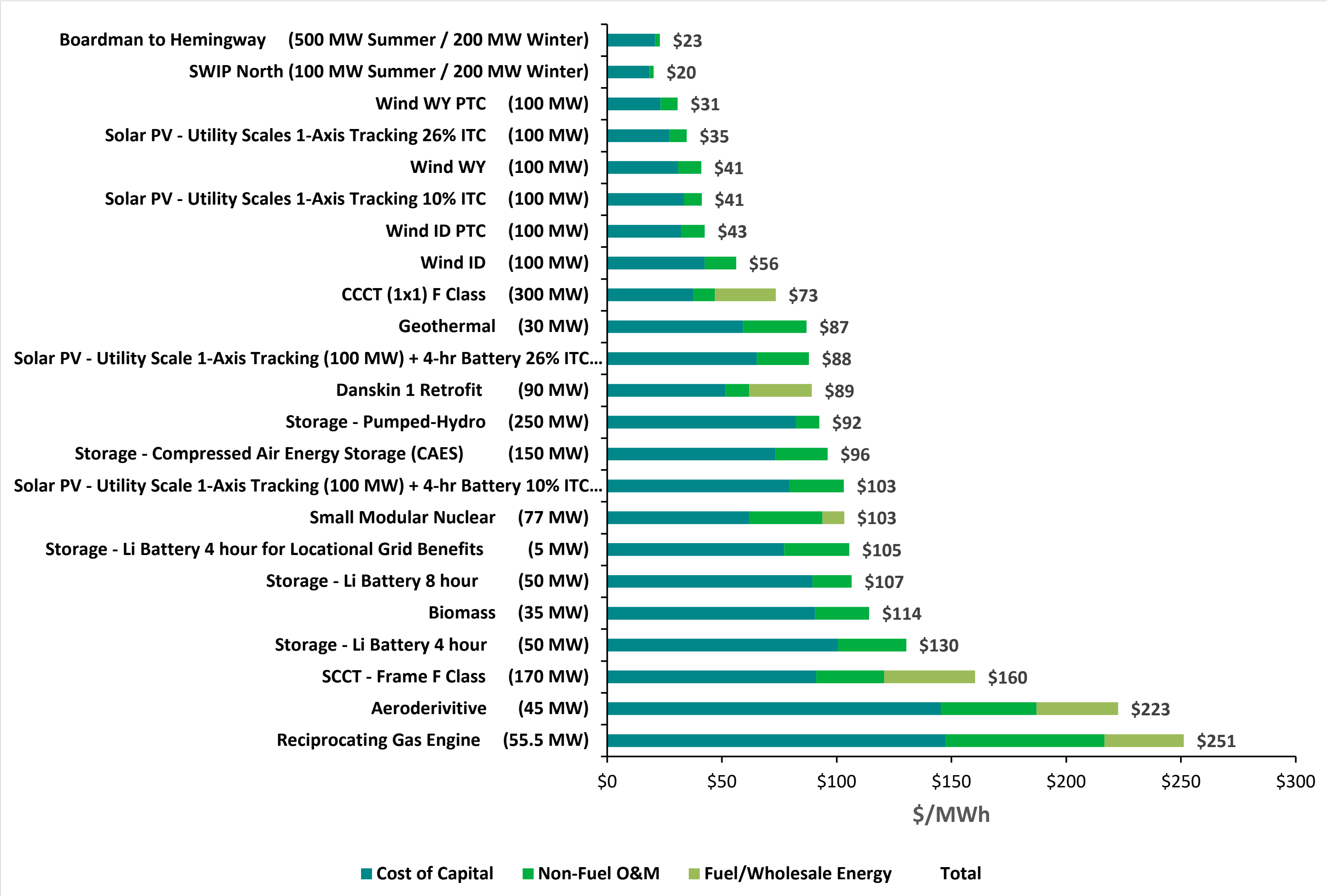

Figure 8.6 Levelized cost of energy (at stated capacity factors) in 2021 dollars

Resource Attributes—IRP Resources

While the cost metrics described in this section are informative, caution must be exercised when comparing costs for resources providing different attributes to the power system. For the LCOC metric, this critical distinction arises because of differences for some resources between *installed* capacity and *peaking* capacity. Specifically, for VERs, an installed capacity of 1 kW equates to an on-peak capacity of less than 1 kW. For example, Idaho wind is estimated to have an LCOC of $12 per month per kW of installed capacity.[30] However, assuming wind delivers an ELCC equal to 11.2% of installed capacity, the LCOC ($12/month/kW) converts to $107 per month per kW of peaking capacity.

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

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

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

Table 8.4 Resource attributes

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

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

The following resource attributes are considered in this analysis:

- *Variable energy*—Renewable resources characterized by variable output and potentially causing an increased need for resources providing balancing or flexibility
- *Dispatchable capacity-providing*—Resources that can be dispatched as needed to provide capacity during periods of peak-hour loading or to provide output during generally high-value periods
- *Non-dispatchable (coincidental) capacity-providing*—Resources whose output tends to naturally occur with moderate likelihood during periods of peak-hour loading or during generally high-value periods
- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from VERs
- *Energy-providing*—Resources producing or reducing the need for energy that are relatively predictable when averaged over long time periods (i.e., monthly or longer)

Table 8.4 provides classification of potential IRP resources with respect to the above attributes. The table also provides cost information on the estimated size potential and scalability for each resource.

IRP REPORT:
PORTFOLIOS

9. PORTFOLIOS

Prior to modeling for the 2021 IRP, Idaho Power conducted an extensive review of IRP model inputs, system settings and specifications, and model validation and verification. The objective of the review was to ensure accuracy of the company's modeling methods, processes, and, ultimately, the IRP results. The review was a preliminary step prior to modeling for the 2021 IRP. As a result, the sections below describe work that began where the review process concluded. For further detail on the IRP review process, refer to the *2019 IRP Review Report*.

Capacity Expansion Modeling

For the 2021 IRP, Idaho Power used the LTCE capability of AURORA to produce optimized portfolios under various future conditions. The logic of the LTCE model optimizes resource additions and exits based on the performance of each zone defined within the WECC. As Idaho Power's electrical system was modeled as a separate zone, the resource portfolios produced by the LTCE and examined in this IRP are optimized for Idaho Power. The optimized portfolios discussed in this document refer to the addition of supply-side and demand-side resources for Idaho Power's system and exits from current coal-generation units.

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

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

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

        - 4 Hour Transmission Connected (between 0 and 1,000 MW)
        - 4 Hour Distribution Connected (between 0 and 100 MW)
        - 8 Hour Transmission Connected (between 0 and 500 MW)

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

Planning Margin

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

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

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

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

Table 9.1 Planning margin calculation breakdown

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

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

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

Portfolio Design Overview

The AURORA LTCE process develops resource portfolios under varying future conditions, or sensitivities for natural gas prices, carbon costs, load growth and electrification, transmission, and clean energy constraints and timelines. The LTCE applies a planning margin hurdle and regulation reserve requirements, and then optimizes resource selections around those constraints to determine a least-cost, least-risk portfolio. Available future resources possess a wide range of operating, development, and environmental attributes. Impacts to system reliability and portfolio costs of these resources depend on future assumptions. Each portfolio consists of a combination of resources derived from the LTCE process that should enable Idaho Power to supply cost-effective electricity to customers over the 20-year planning period.

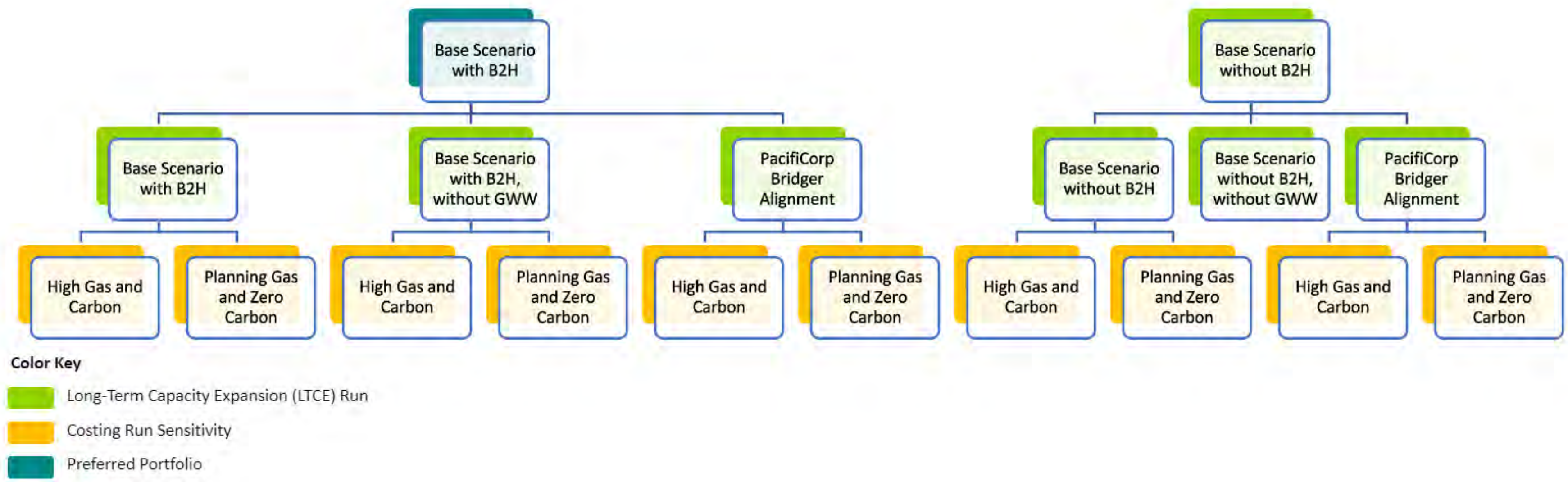

Figure 9.1 Branching analysis diagram

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

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

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

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

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

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

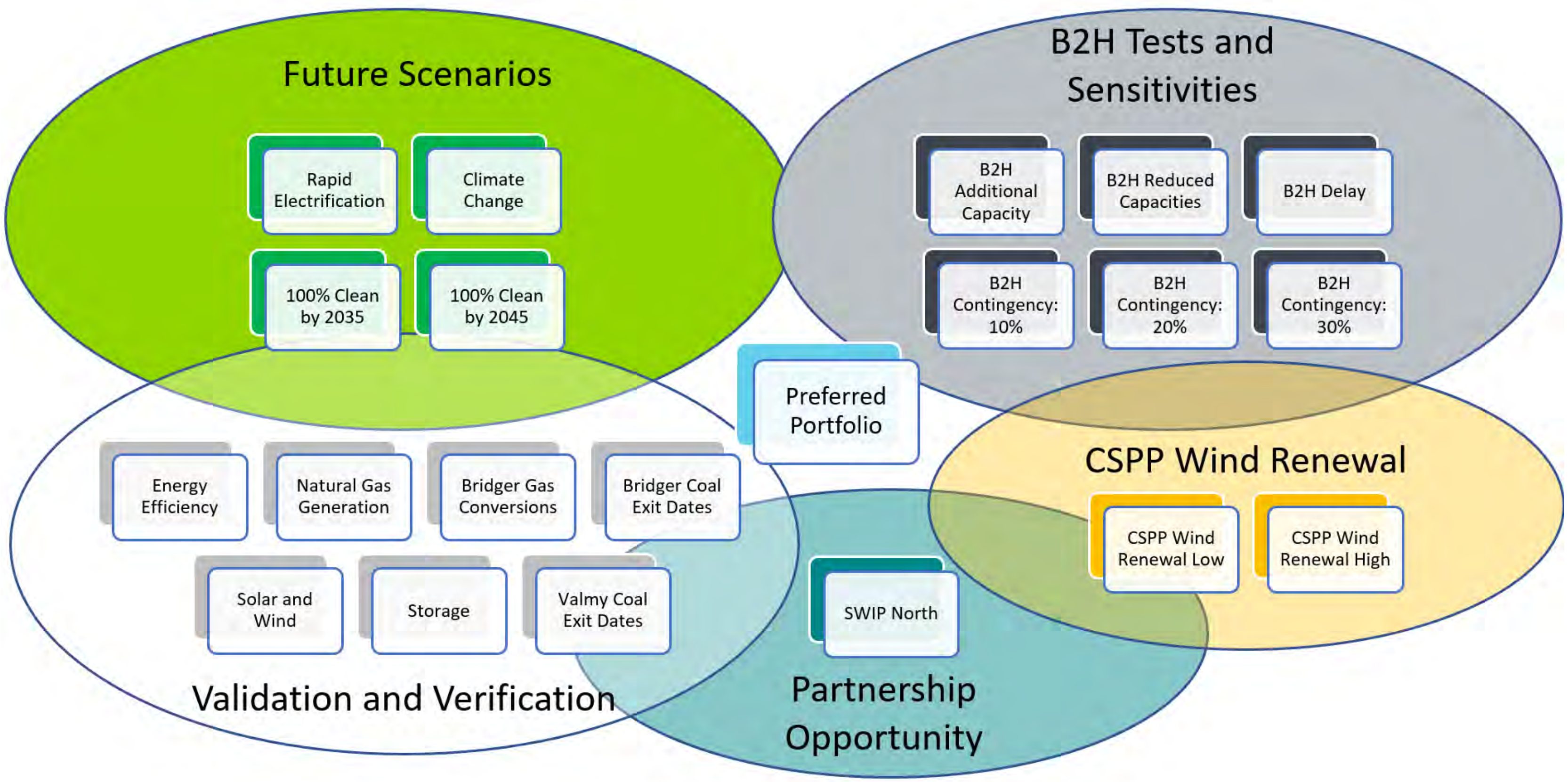

Figure 9.2 Sensitivity analysis diagram

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

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

Future Scenarios—Purpose: Risk Evaluation

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

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

Rapid Electrification

The company forecasts moderate building and transportation electrification in all scenarios. The Rapid Electrification scenario was developed to determine what kind of adjustments would need to be made to the plan to accommodate a very rapid transition toward electrification. This rapid transition includes increasing the electric vehicle forecast and the penetration of electric heat pumps for building heating and cooling each by a factor of 10. This aggressive forecast assumes over a half-million electric vehicles as well as adoption of an 80% penetration of heat pump technology at residences within the company's service area. These levels are blended into the load forecast over the next 20 years and do not factor in current economic consumer choice or the impact of existing legislation and/or incentives. The Rapid Electrification scenario is meant to serve as a high bookend on what is possible with the transition to electrification. As a bookend, the Rapid Electrification scenario is considered improbable.

Climate Change

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

100% Clean by 2035 Scenario

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

The struggles of the model to achieve a 100% Clean by 2035 scenario are indicative of the challenges faced by the industry to meet a 100% target given technologies commercially available today. Technology breakthroughs, such as cost-effective long-duration energy storage, nuclear energy, or hydrogen, will likely be required to meet this goal.

100% Clean by 2045 Scenario

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

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

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

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

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

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

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

Model Validation and Verification—Purpose: Model Validation and Verification

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

Demand Response

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

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

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

Energy Efficiency

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

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

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

Natural Gas Generation and Solar Plus Storage

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

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

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

Bridger Natural Gas Conversion (Units 1 and 2)

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

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

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

Bridger Coal Exit Dates (Units 3 and 4)

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

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

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

Geothermal and Biomass

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

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

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

Valmy

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

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

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

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

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

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

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

Regulation Reserves

The 2020 VER Study provided the rules to define hourly reserves needed to reliably operate the system based on current and future quantities of solar and wind generation and load forecasted by season and time of day. The reserves are defined separately, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2021 IRP include defining hourly reserve requirements for "Load Up," "Load Down," "Solar Up," "Solar Down," "Wind Up," and "Wind Down."

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

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

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

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

Natural Gas Price Forecasts

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

Carbon Price Forecasts

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

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

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

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

3. High Carbon Costs—is based on a federal interagency working group Technical Support Document: *Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.*[34] The carbon cost forecast assumes a price of approximately $53 per ton beginning in 2021 that increases to more than $105 per ton (nominal dollars) by the end of the IRP planning horizon.

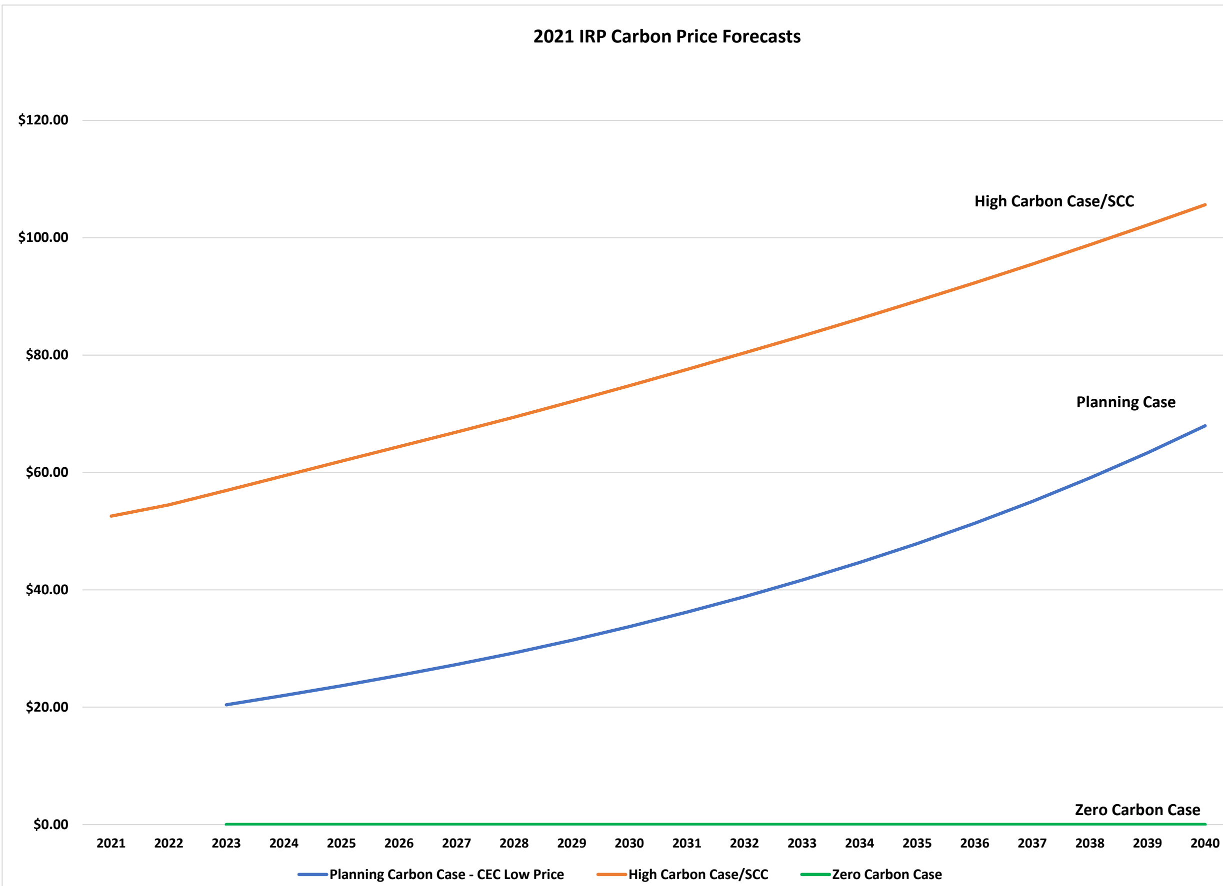

Figure 9.3 Carbon price forecast

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

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

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IRP REPORT:

MODELING ANALYSIS

10. MODELING ANALYSIS

Portfolio Cost Analysis and Results

Once the portfolios are created using the LTCE model, Idaho Power uses the AURORA electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data. It should be noted that the Portfolio Cost Analysis is a step that occurs *following* the development of the resource buildouts through the LTCE model; the Portfolio Cost Analysis utilizes the resource buildouts from the LTCE model as an input. The LTCE and Portfolio Cost analyses are performed sequentially.

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

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

Table 10.1 Financial assumptions

Financial Variable	Value
Discount rate (weighted average capital cost)	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.30%
Annual property tax rate (% of investment)	0.47%
B2H annual property tax rate (% of investment)	0.64%
Property tax escalation rate	3.00%
B2H property tax escalation rate	0.68%
Annual insurance premium (% of investment)	0.049%
B2H annual insurance premium (% of investment)	0.004%
Insurance escalation rate	3.00%
B2H insurance escalation rate	3.00%
AFUDC rate (annual)	7.45%

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

Table 10.2 AURORA hourly simulations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Portfolio Emission Results

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

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

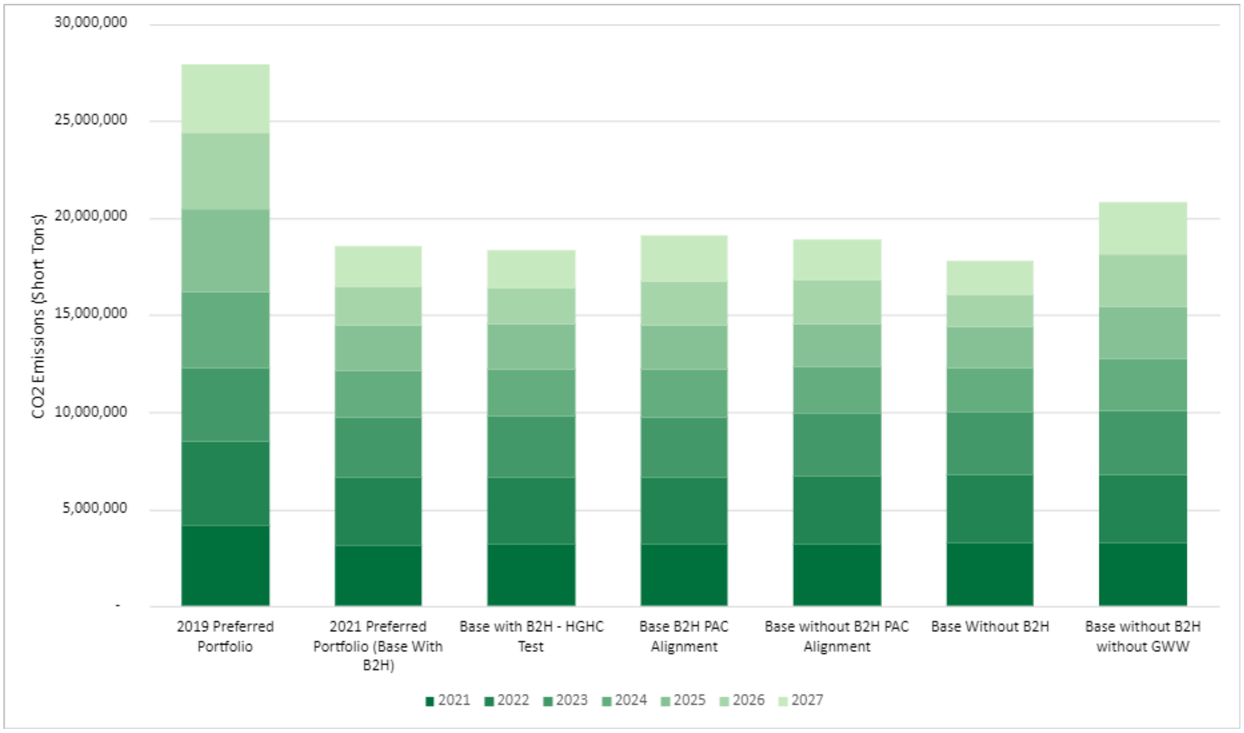

Figure 10.1 Estimated Action Plan window portfolio emissions from 2021–2027

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

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

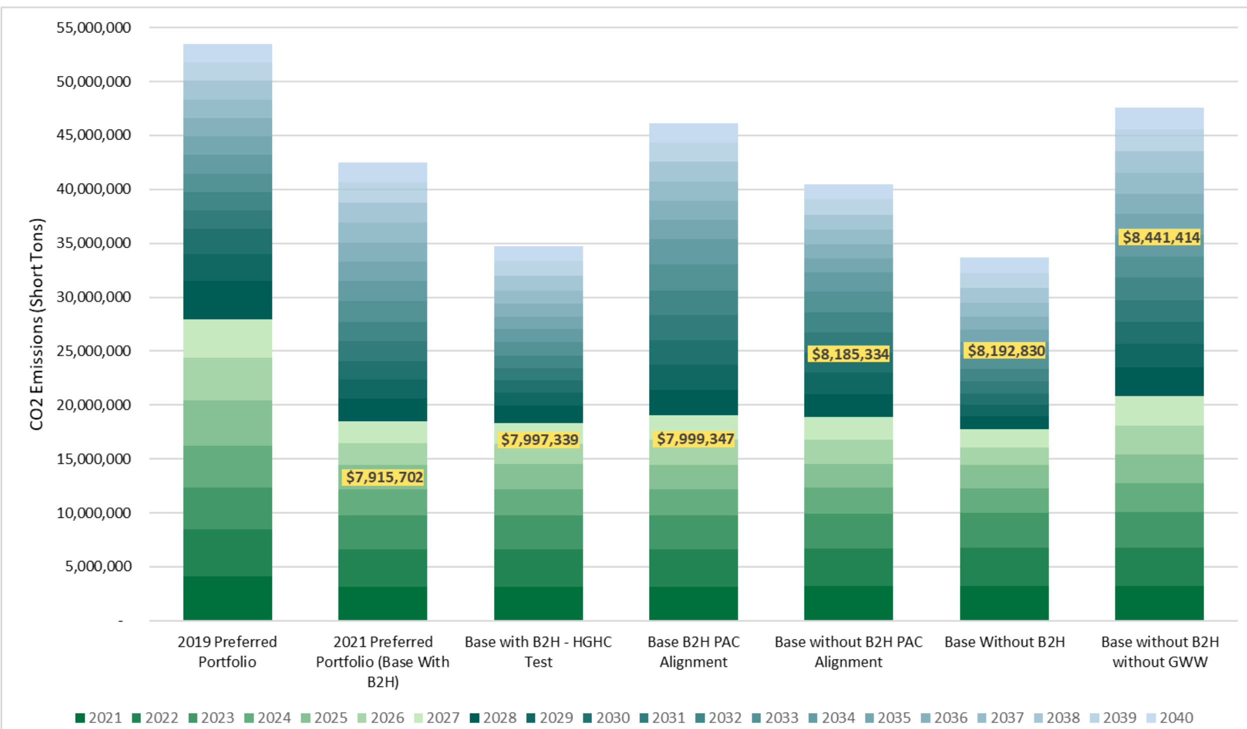

Figure 10.2 Estimated portfolio emissions from 2021–2040

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

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

Qualitative Risk Analysis

Major Qualitative Risks

Fuel Supply—All generation and transmission resources require fuel to provide electricity. Different resource types have different fuel supply risks. Renewable resources rely on uncertain future weather conditions to provide the fuel be it wind, sun, or water. Weather can be variable and difficult to forecast accurately. Thermal resources like coal and natural gas rely on fuel supply infrastructure to produce and transport fuel by rail or pipeline and include mining or drilling facilities. Fuel supply infrastructure has several risks when evaluating resources-it is susceptible to outages from weather, mechanical failures, labor unrest, etc. Fuel supply infrastructure can be limited in its existing availability to increase delivery of fuel to a geographic area that limits the amount of new resources dependent on the capacity constrained infrastructure.

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

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

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

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

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

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

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

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

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

Table 10.6 Qualitative risk comparison

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

Operational Considerations

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

Stochastic Risk Analysis

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

The purpose of the analysis is to help understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations) and how the ranges for portfolios differ. It is used to identify the probabilities of various risk and the shape of that risk. To assess stochastic risk, the key drivers of natural gas prices, customer load, and hydroelectric generation are allowed to vary based on their historical variance. A full description of how these variables were modeled in the stochastic analysis can be found in the Stochastic Risk Analysis section of *Appendix C—Technical Report* of the 2021 IRP.

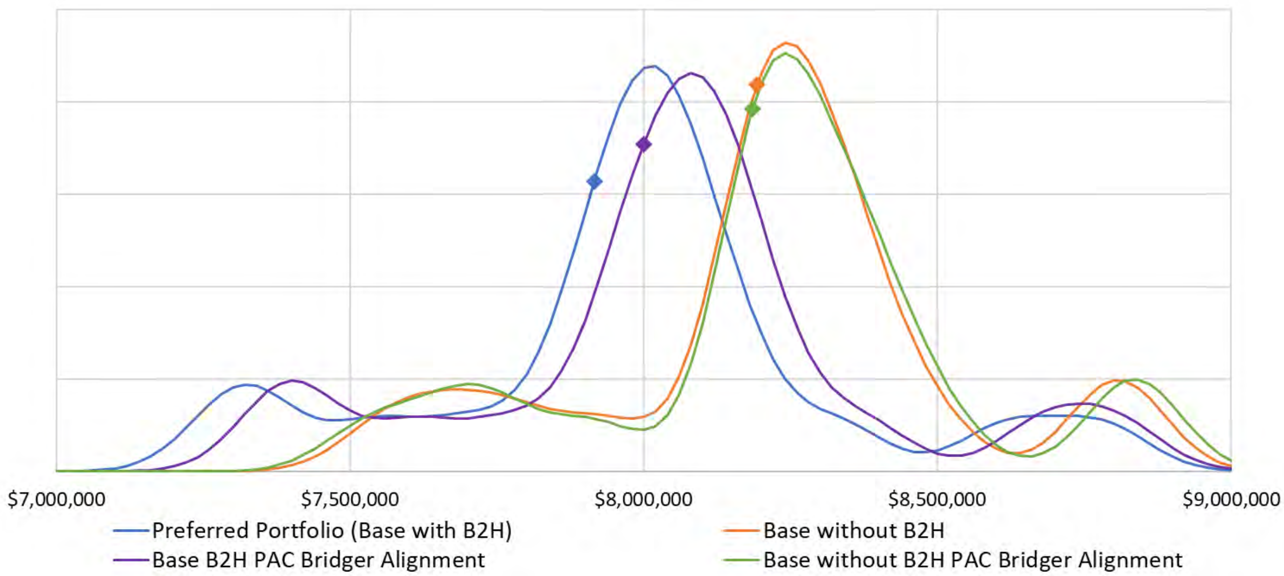

Figure 10.3 NPV stochastic probability kernel (likelihood by NPV [$ x 1,000])

In Figure 10.3, each line represents the likelihood of occurrence by NPV with the diamonds showing the planning conditions NPV. Higher values on the line represent a higher probability of occurrence with values near the horizontal axis representing improbable events. Values that occur toward the left have lower cost while values toward the right have higher cost.

As indicated by the peak of the graph being furthest left, the results of the stochastic analysis show that the Preferred Portfolio (Base with B2H) has the lowest cost given a range of natural gas prices, load forecasts, and hydroelectric generation levels. Next lowest is the Base with B2H PAC Bridger Alignment portfolio indicated by the middle peak. Nearly tied as the most expensive options analyzed using stochastic elements are both Base without B2H portfolios regardless of PAC Bridger Alignment.

Loss of Load Evaluation of Portfolios

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

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

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

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

LOLE Results of Selected Portfolios

The annual LOLE values were calculated for the following portfolios:

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

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

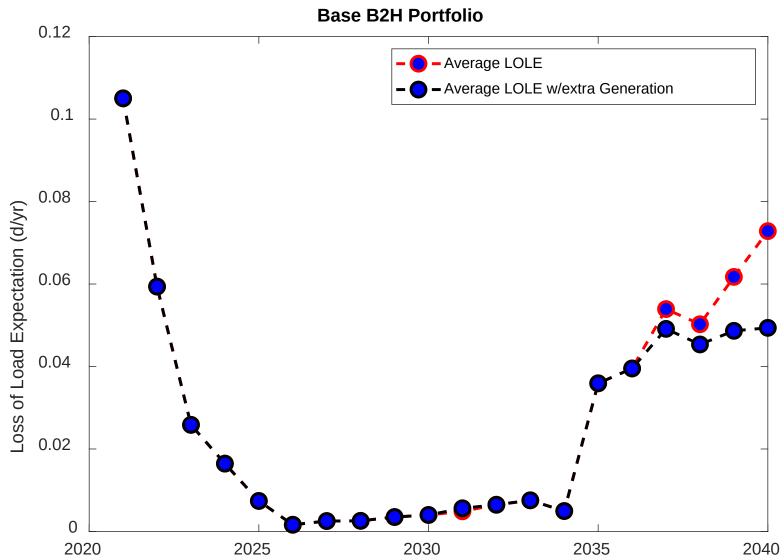

Figure 10.4 Annual loss of load expectation for the Preferred Portfolio

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

Capacity Planning Margin

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

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

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

Table 10.7 July peak hour load and resource balance

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

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

SWIP-North Opportunity Evaluation

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

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

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

B2H Robustness Testing

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

B2H Capacity Evaluation

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

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

Table 10.8 B2H capacity sensitivities

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

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

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

B2H Cost Risk Evaluation

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

Table 10.9 B2H cost sensitivities

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

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

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

B2H In-Service Date Risk Evaluation

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

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

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

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

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

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

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

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

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

Table 10.11 Coal retirement forecast

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

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

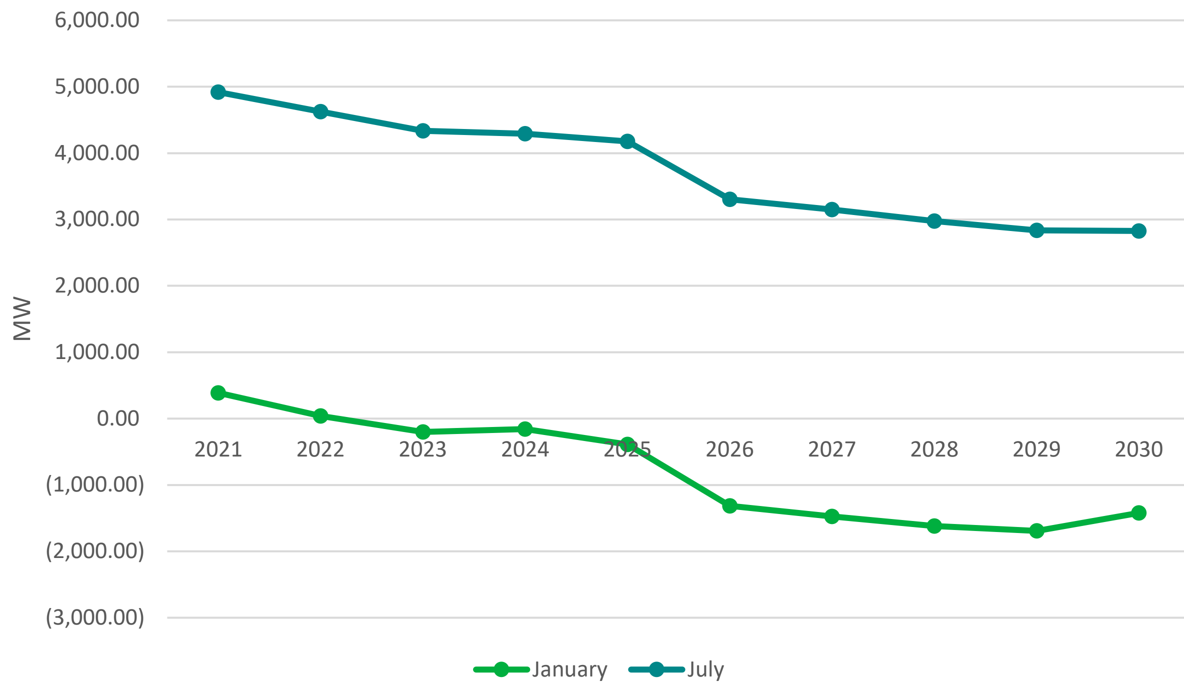

Figure 10.5 BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

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

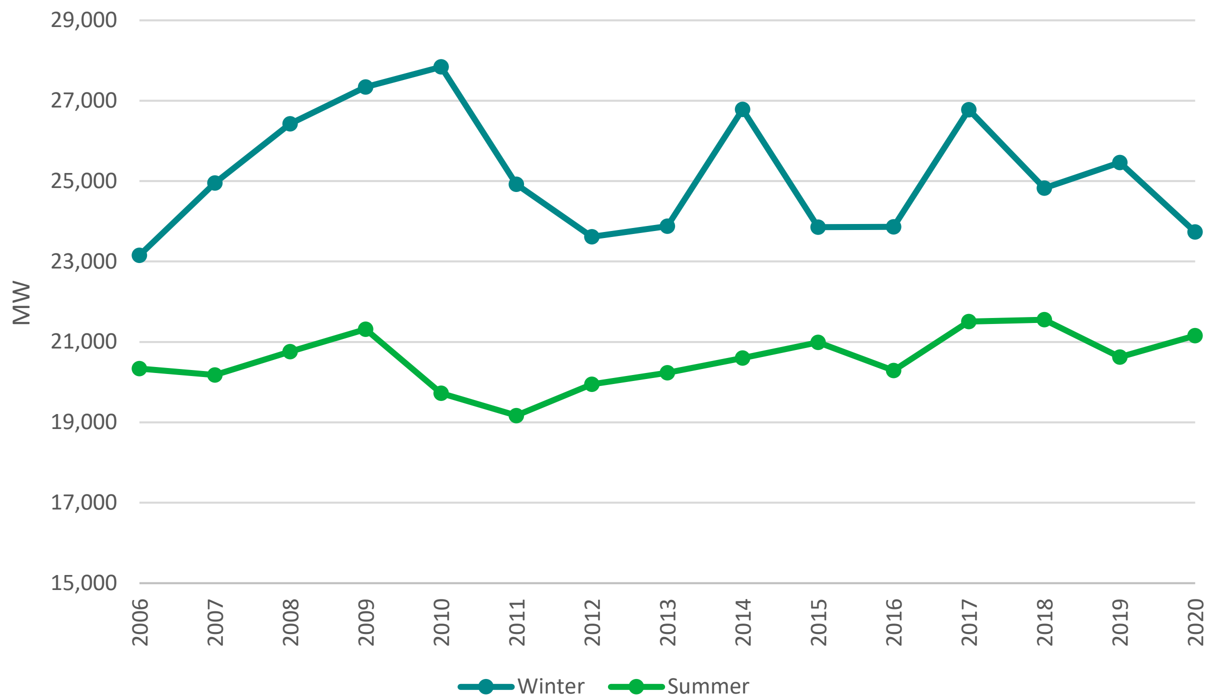

Figure 10.6 Peak coincident load data for most major Washington and Oregon utilities

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

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

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

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IRP REPORT:

PREFERRED PORTFOLIO AND ACTION PLAN

11. PREFERRED PORTFOLIO AND ACTION PLAN

Preferred Portfolio

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

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

Table 11.1 AURORA hourly simulations

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

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

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

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

The Preferred Portfolio (Base with B2H) follows.

Table 11.2 Preferred Portfolio additions and coal exits (MW)

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

The following items are included in Table 11.2:

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

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

Preferred Portfolio Compared to Varying Future Scenarios

Rapid Electrification

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

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

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

Table 11.3 Preferred Portfolio and Rapid Electrification scenario comparison

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

Climate Change

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

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

Table 11.4 Preferred Portfolio and Climate Change scenario comparison

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

100% Clean by 2035

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

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

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

100% Clean by 2045

Idaho Power set a goal to provide 100% clean energy by 2045. A comparison of resources selected in the Preferred Portfolio compared to the resource selection that adheres to emission constraints that linearly lead to the goal is shown below. The path to clean energy may not be linear and these assumptions were made to create a comparison scenario.

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

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

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

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

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

CSPP Wind Renewal Low

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

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

Table 11.7 Preferred Portfolio and CSPP Wind Renewal Low scenario comparison

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

CSPP Wind Renewal High

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

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

Table 11.8 Preferred Portfolio and CSPP Wind Renewal High scenario comparison

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

Action Plan (2021–2027)

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

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

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

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

Action Plan (2021–2027)

Table 11.9 Action Plan (2021–2027)

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

Resource Procurement

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

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

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

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

Urgent Capacity Resource Need

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

Changes in the Load and Resource Balance Since the 2019 IRP

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

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

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

Transmission Market Shifts and Constraints

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

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

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

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

Planning Margin Adjustments

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

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

Load Forecast Increases

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

Load and Resource Balance in the 2021 IRP

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

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

2021 RFP

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

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

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

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

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

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

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

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

2022 All Source RFP

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

Alternative Acquisition Method

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

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

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

Conclusion

The 2021 IRP provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. The B2H transmission line continues in the 2021 IRP analysis to be a top performing resource alternative, providing Idaho Power access to affordable and clean energy in the Pacific Northwest wholesale electric market. From a regional perspective, the B2H transmission line, and high-voltage transmission in general, is critical to achieving cost-effective clean energy objectives, including Idaho Power's goal of 100% clean energy by 2045.

Idaho Power linemen install upgrades.

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

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

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

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

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

IDAHO POWER
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DECEMBER • 2021

A VIEW
FROM ABOVE

IRP
INTEGRATED RESOURCE PLAN

APPENDIX A: **SALES & 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 *2021 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 2021 through 2040.

This appendix describes the development of the anticipated monthly 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 anticipated 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 anticipated case economic/demographic variables by applying historically based parameters of growth on both the low and high side of the economic determinants of the anticipated case forecast.

Economic data in the forecast models is primarily sourced from Moody's Analytics and Woods & Poole Economics. 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 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 said economic data include, but are not limited to, the Idaho Department of Labor, 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 2% 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 2.6% 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 anticipated forecast are tested utilizing a probabilistic distribution of normal weather (temperature and precipitation) applied to the weather assumptions in the anticipated case. This provides a comparative range of outcome that isolates long-term sustained weather influences on the forecast.

The forecast of the anticipated scenario shows, Idaho Power's system load is forecast to increase to 2,482 average megawatts (aMW) by 2040 from 1,895 aMW in 2021, representing an average yearly growth rate of 1.4% over the 20-year planning period (2021–2040). A similar annual average growth rate in system load is reflected in various weather-related scenarios. From an annual peak-hour demand perspective, the anticipated case of the peak demand forecast will grow to 4,700 megawatts (MW) in 2040 from the all-time system peak of 3,751 MW that occurred on Wednesday, June 30, 2021, at 5 p.m. Idaho Power's system peak increases at an average growth rate of 1.4% per year over the 20-year planning period (2021–2040) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2020 level of 586,071 customers to nearly 851,849 customers by year-end 2040.

Beyond the weather, climate, economic and demographic assumptions used to drive the anticipated 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 2020 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.

Outside of weather, potential primary 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.

2021 IRP SALES AND LOAD FORECAST

Average Load

The economic and demographic variables driving the 2021 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 post Great Recession history. From that point, the global pandemic recession in 2020 had profound effects across the national and global economy. For the company, residential sales increased approximately 5% in 2020 and into 2021. This growth is attributable to both work-from-home edicts as well as continued strong in-migration trends. Negative energy use was initially exhibited by the commercial and industrial classes but have since stabilized and, overall, rebounded quickly. Irrigation sales were mostly unaffected by the pandemic. It is expected that economic conditions return to long-term fundamentals during the 2021 IRP forecast term. COVID-19 impacts are further discussed in the individual class sections below. Additional significant factors and considerations that influenced the outcome of the 2021 IRP load forecast include the following:

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

- The economic forecast used for the 2021 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. The state of Idaho had the highest residential population growth rate of any state in the United States over the past 5 years (ending 2020). Customer additions experienced prior to the housing bubble 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.

- Although interest from large customers has been robust, there is some uncertainty associated with these industrial and special contract customers due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an uncertain magnitude of the energy and peak-demand requirements. The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating in the service area. The large numbers of prospective businesses that have indicated some interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the anticipated sales and load forecast.
- The electricity price forecast used to prepare the sales and load forecast in the 2021 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price forecast yields lower future prices. The retail prices are mostly lower throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.
- As discussed above, the response to the novel corona virus influenced electric usage behavior across the major rate classes. Discernably, these impacts tended to balance one another; e.g., increased residential consumption due to work-from-home behavior was offset by decreased use from office and other commercial facilities. While these impacts continue to play out in decreasing importance, the impact on the long-term forecast horizon is essentially inconsequential.

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 50th, 90th, and 95th-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 3,751 MW, recorded on Wednesday, June 30, 2021, at 7 p.m. The previous all-time system summer peak demand, adjusted for demand response, was 3,437 MW, recorded on Friday, July 2, 2013, at 5 p.m. Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9 a.m. and matched the previous record peak dated December 10, 2009, at 8 a.m.
- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1991 to 2020 time period (the most recent 30 years).
- The 2021 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 are 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 hourly 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 anticipated 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 anticipated average load forecast assumes median temperatures and median precipitation (i.e., there is a 50% chance loads will be higher or lower than the anticipated 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 1991 to 2020 (the most recent 30 years) was 1,024 at the Boise Weather Service office. The 70^{th}-percentile HDD is 1,048 and would be exceeded in 3 out of 10 years. The 90^{th}-percentile HDD is 1,130 and would be exceeded in 1 out of 10 years. As an example, for a single month, the near 100^{th}-percentile HDD (the coldest December over the 30 years) is 1,284, which occurred in December 2016. 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 2021 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
Anticipated 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	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	2,001	2,197	2,427	2,620	1.4%
70th Percentile	1,941	2,132	2,357	2,541	1.4%
Anticipated Case	1,895	2,082	2,304	2,482	1.4%

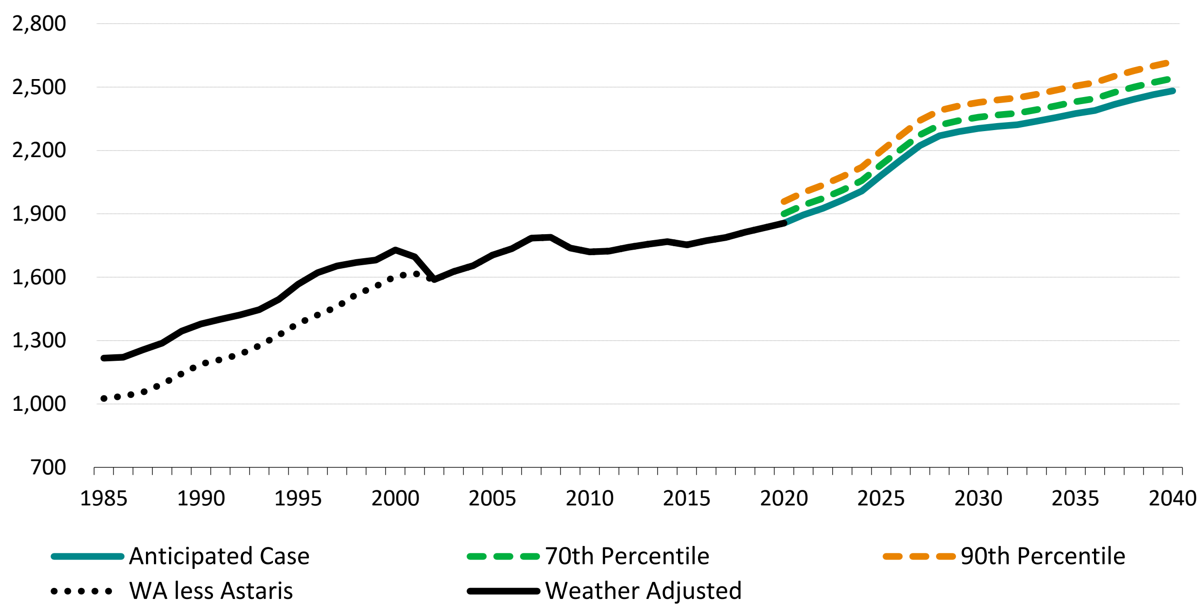

Figure 1. **Forecast system load (aMW)**[1]

Load Forecasts Based on Economic Uncertainty

The anticipated 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 anticipated case forecast. The forecasts provide a range of possible load growth rates for the 2021 to 2040 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 (1996–2020).

Of the three scenarios 1) the anticipated forecast is the median growth path, 2) the standard deviation observed during the historical time is used to estimate the dispersion around the anticipated scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1996–2020).

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

[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.

and are reported 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% 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% 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% 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%
Anticipated 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%
Anticipated 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 (including past sales to Astaris, Inc. [aka FMC]) and on system contracts (including past sales to Raft River Coop and the City of Weiser).

Results of Idaho Power's economic scenario probabilistic system load projections are reported in Table 4 and shown in Figure 2. The anticipated system load-forecast growth rate averages 1.4% per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 1.1% per year throughout the forecast period. The high scenario projects a load growth of 1.8% 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% of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Low	1,859	1,991	2,166	2,277	1.1%
Anticipated	1,895	2,082	2,304	2,482	1.4%
High	1,942	2,190	2,461	2,731	1.8%

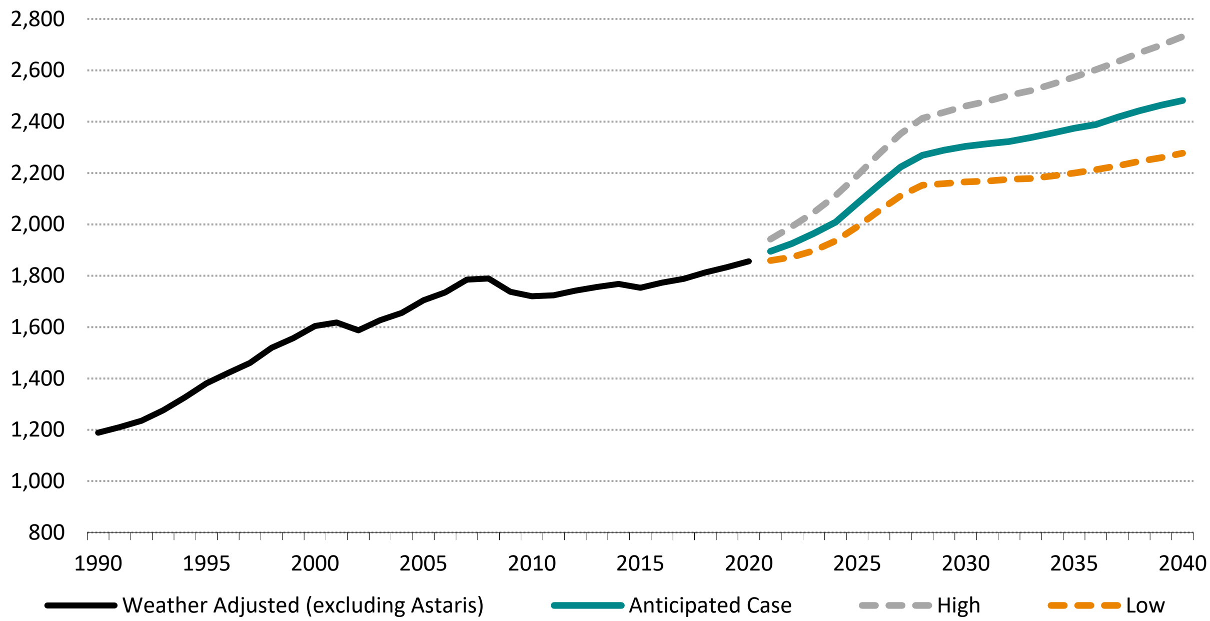

Figure 2. Forecast system load (aMW)

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 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 anticipated 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 load growth of the anticipated system forecast averages 1.4% per year from 2021 to 2040. Company system load projections are reported in Table 2 and shown in Figure 1.

In the anticipated forecast, the company system load is expected to increase from 1,895 aMW in 2021 to 2,482 aMW in 2040, an average annual growth rate of 1.4%. In the weather sensitive scenarios, the 70th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,941 aMW in 2021 to 2,541 aMW by 2040 and increase from 2,001 aMW in 2021 to 2,620 aMW, respectively. All scenarios have an average growth rate of 1.4% per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,859 aMW in 2021 to 2,277 aMW in 2040, an average annual growth rate of 1.1% and in the high case from 1,942 aMW to 2,731 aMW, an average annual growth rate of 1.8% (Table 2).

The system load, excluding Astaris (formerly known as FMC), portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive regarding the impact of a loss or gain of a significant large-load customer on system load.

Accompanied by the outlook of economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is expected. Total load is made up of system load plus long-term, firm, off-system contracts. Currently, 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 16% higher in 2040, gaining 0.9 million megawatt-hours (MWh) over 2021. Commercial sales are expected to be 19% higher, or 0.8 million MWh, followed by industrial (35% higher, or 0.9 million additional MWh) and irrigation (12% higher in 2040 than 2021). Additional firm sales are expected to more than triple by 2040, gaining 2.1 million MWh over 2021.

In addition to the above anticipated sales forecast, differing weather probabilities, high and low economic cases, and alternative sales and load cases were developed for analysis within the

2021 IRP. These include high growth within commercial and industrial classification of an additional approximate 250 MW of capacity requirements, high penetration future of building and transportation electrification, and future potential climate change impacts to the load forecast.

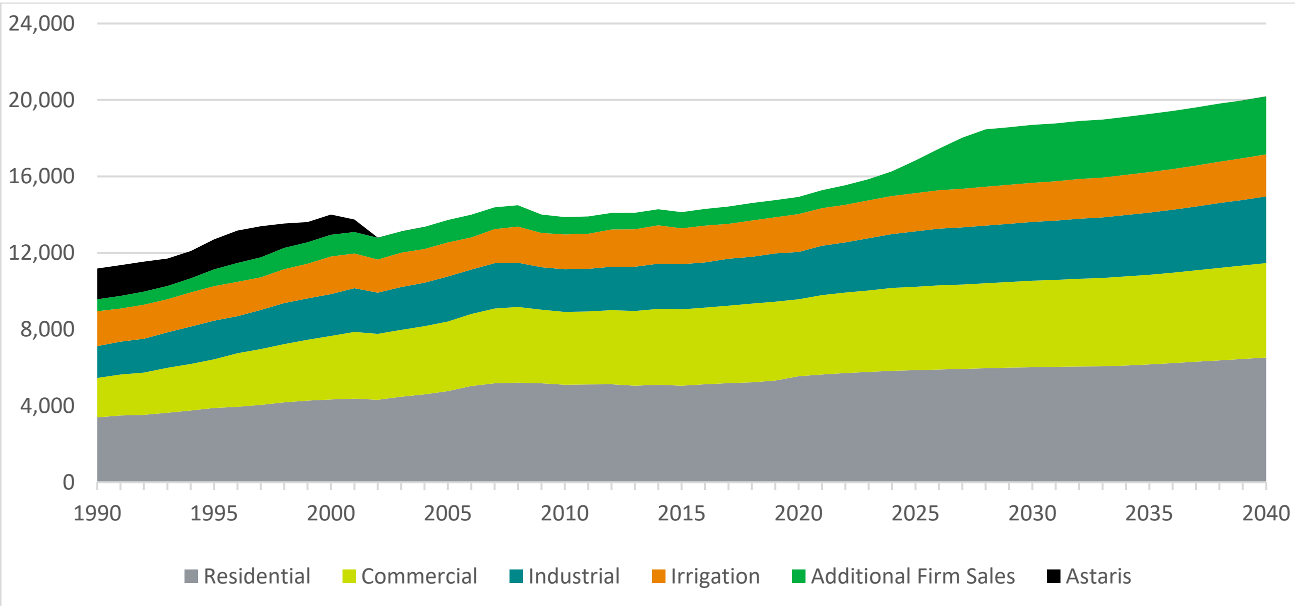

Figure 3. Composition of system company electricity sales (thousands of MWh)

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 3,751 MW, recorded on Wednesday, June 30, 2021, at 7 p.m. The previous all-time system summer peak demand, adjusted for demand response, was 3,437 MW, recorded on Friday, July 2, 2013, at 5 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.

In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,771 MW in 2021 to 4,868 MW in 2040. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,745 MW in 2021 to 4,842 MW in 2040. Finally, in the 50th-percentile, or anticipated case, the system summer peak load increases from 3,603 MW in 2021 to 4,700 MW in 2040. All of which represent an average summer peak growth rate of 1.4% per year over the planning period (Table 5).

Table 5. System summer peak load growth (MW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
95th Percentile	3,771	4,071	4,421	4,868	1.4%
90th Percentile	3,745	4,045	4,394	4,842	1.4%
50th Percentile	3,603	3,903	4,252	4,700	1.4%

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% curtailment in irrigation load due to a voluntary load reduction program.

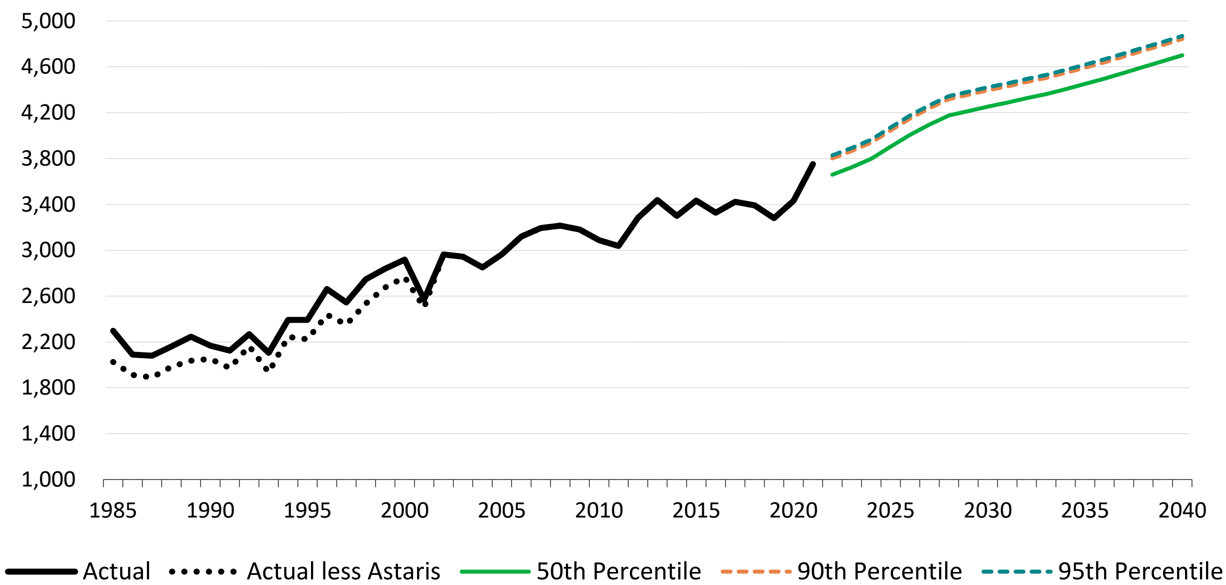

Figure 4. **Forecast system summer peak (MW)**

As of December 31, 2019, the all-time system winter peak demand of 2,527 MW, realized on Thursday, December 10, 2009, at 8 a.m. was matched on January 6, 2017, at 9 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 greater 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 2,699 MW in 2021 to 3,328 MW in 2040, an average growth rate of 1.1% per year over the planning period. In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,584 MW in 2021 to 3,262 MW in 2040, an average growth rate of 1.2% per year over the planning period. In the 50th-percentile, or anticipated case forecast, the system winter peak load is expected to increase from 2,367 MW in 2021 to 3,132 MW in 2040, an average growth rate of 1.5% per year over the planning period. This data is represented in Table 6. The three scenarios of projected system winter peak load are illustrated in Figure 5.[2]

[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% 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 1991 to 2020 time (the most recent 30 years).

Table 6. System winter peak load growth (MW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
95th Percentile	2,699	2,918	3,142	3,328	1.1%
90th Percentile	2,584	2,803	3,028	3,262	1.2%
50th Percentile	2,367	2,586	2,878	3,132	1.5%

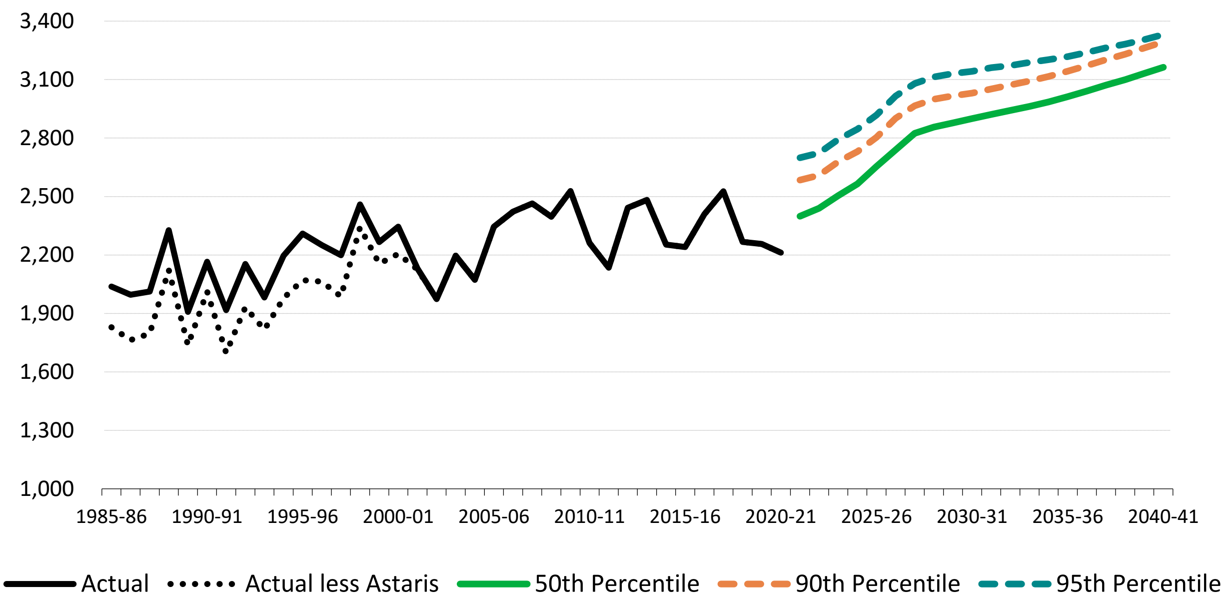

Figure 5. **Forecast system winter peak (MW)**

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, as evidenced by the shift in the most-recent slope lines, has been significantly greater due to the increased presence of urban cooling load in the peak summer months.

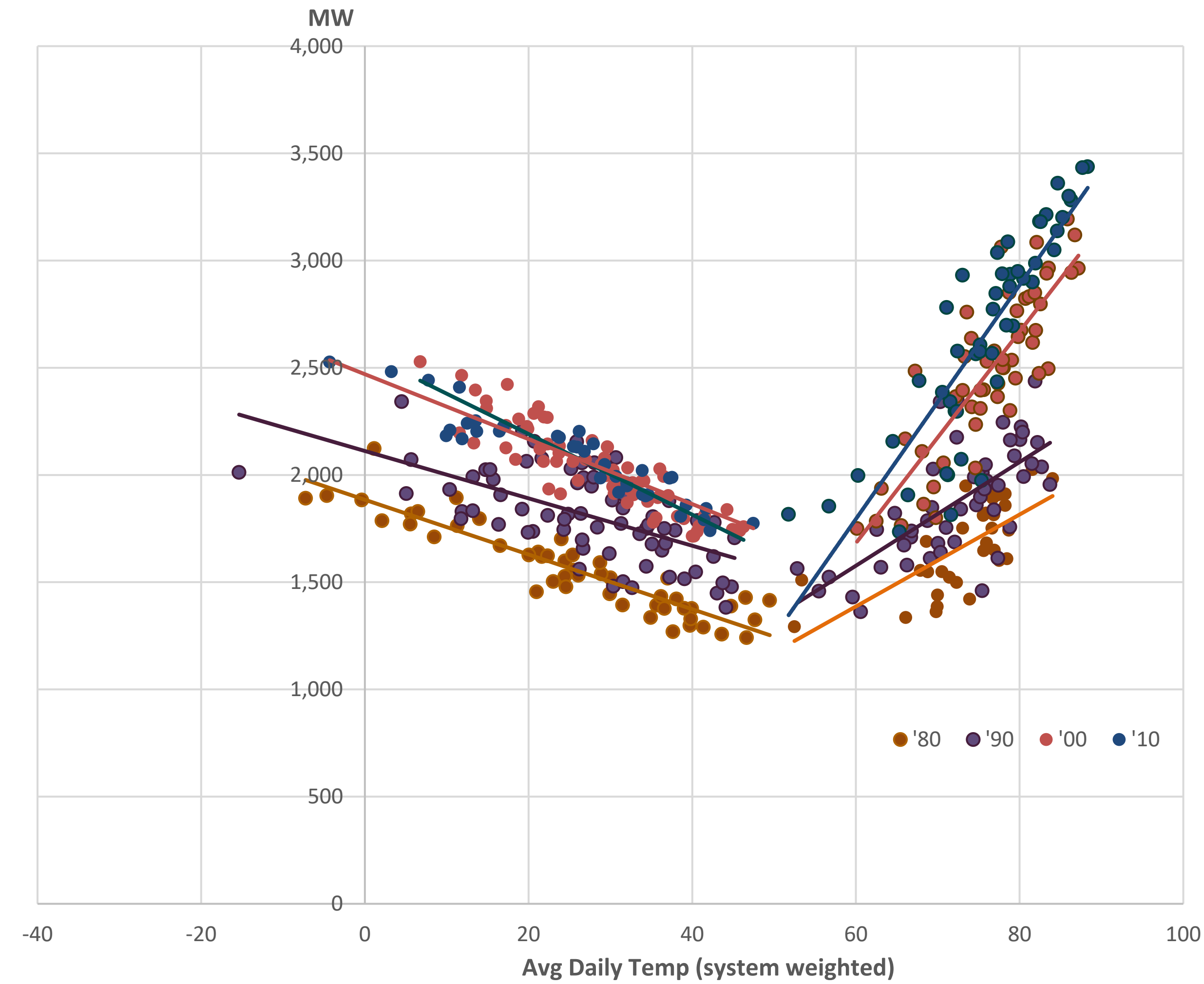

Figure 6. Idaho Power monthly peaks (MW)

Note that the 2021 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 without the interference of load intervention on causal variables. 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 1991 to 2020 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 2040. 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 FORECAST

Residential

The anticipated residential load is forecast to increase from 644 aMW in 2021 to 743 aMW in 2040, an average annual compound growth rate of 0.8%. In the 70th-percentile scenario, the residential load is forecast to increase from 664 aMW in 2021 to 773 aMW in 2040, an average annual compound growth rate of 0.8%, matching the anticipated residential growth rate. The residential load forecasts are reported in Table 7 and shown in Figure 7.

Table 7. Residential load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	691	723	746	812	0.9%
70th Percentile	664	692	712	773	0.8%
Anticipated Case	644	670	687	743	0.8%

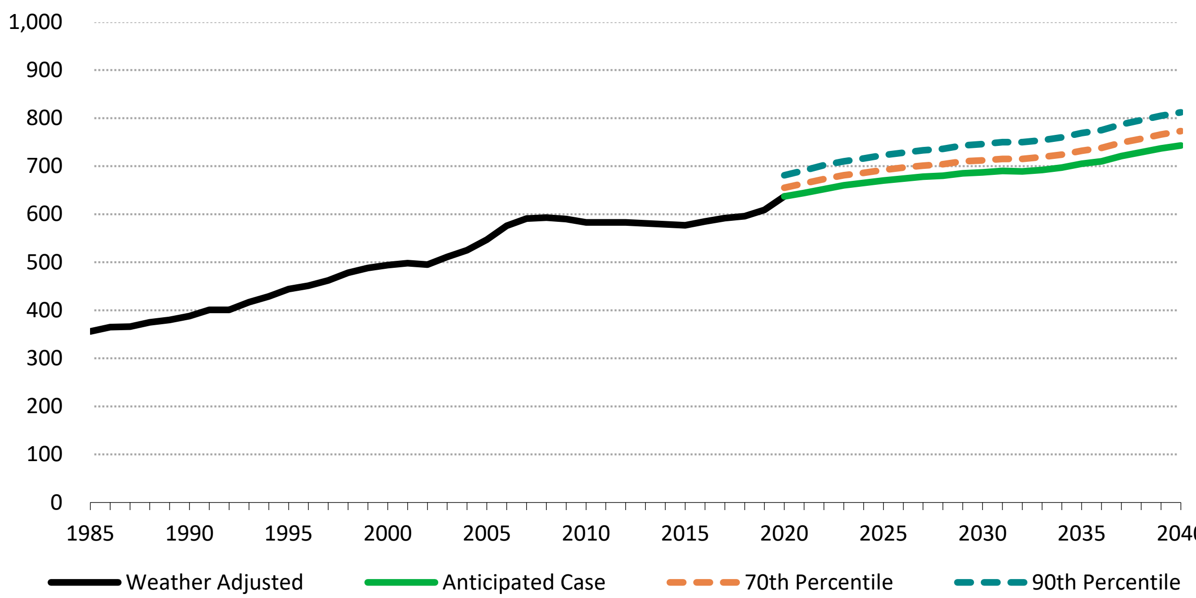

Figure 7. Forecast residential load (aMW)

Sales to residential customers made up 30% of Idaho Power's system sales in 1990 and 37% of system sales in 2020. The number of residential customers is projected to increase to nearly 719,500 by December 2040.

The average sales per residential customer increased to nearly 14,800 kilowatt-hours (kWh) in 1980 before declining to 13,200 kWh in 2001. In 2002, residential use per customer dropped dramatically—over 500 kWh per customer from 2001—the result of significantly higher electricity prices 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 have placed downward pressure on residential use per customer since that point. This trend is expected to continue, declining at 1.1% per year, as the average sales per residential customer are expected to decrease to approximately 9,100 kWh per year by 2040. Average annual sales per residential customer are shown in Figure 8. Although, it is important to note—as evident in figures 7 and 8—the impacts of the COVID pandemic on residential electricity sales (Figure 7) and residential use-per-customer (Figure 8). Major shifts in early 2020 to working and schooling from home, which required retooling homes with computers and electronics, served to boost residential electricity sales and use-per-customer. Residential sales (weather-adjusted) were 4% to 5% higher in 2020 than 2019. In addition to the overall increase in use per customer, the pandemic accelerated in-migration allowing those searching for affordable housing, a more reasonable cost of living, and ability to work from home to move from larger, more populated metro areas. This impact is fortified by Idaho having the highest population growth rate of any state in the United States over the past 5 years (ending 2019)[3] which continues today, as evidenced by Idaho Power's strong customer growth through year-to-date 2021.

[3] United States Census Bureau Population, Population Change, and Estimated Components of Population Change 2010 to 2019.

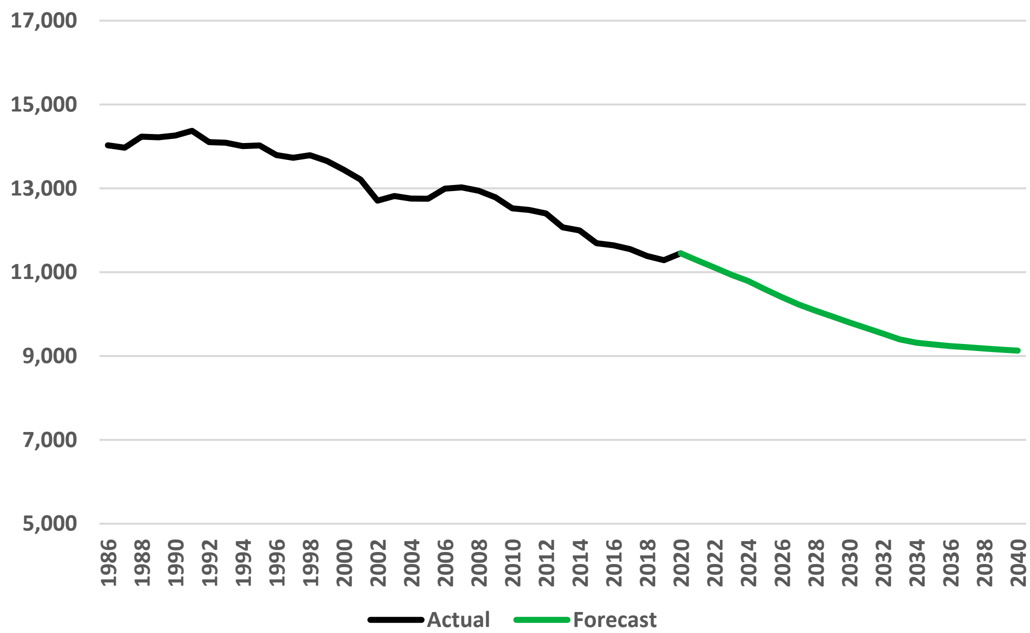

Figure 8. **Forecast residential use per customer (weather-adjusted kWh)**

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 2021 to 2040 shows an average annual growth rate of 1.9% as shown in Figure 9.

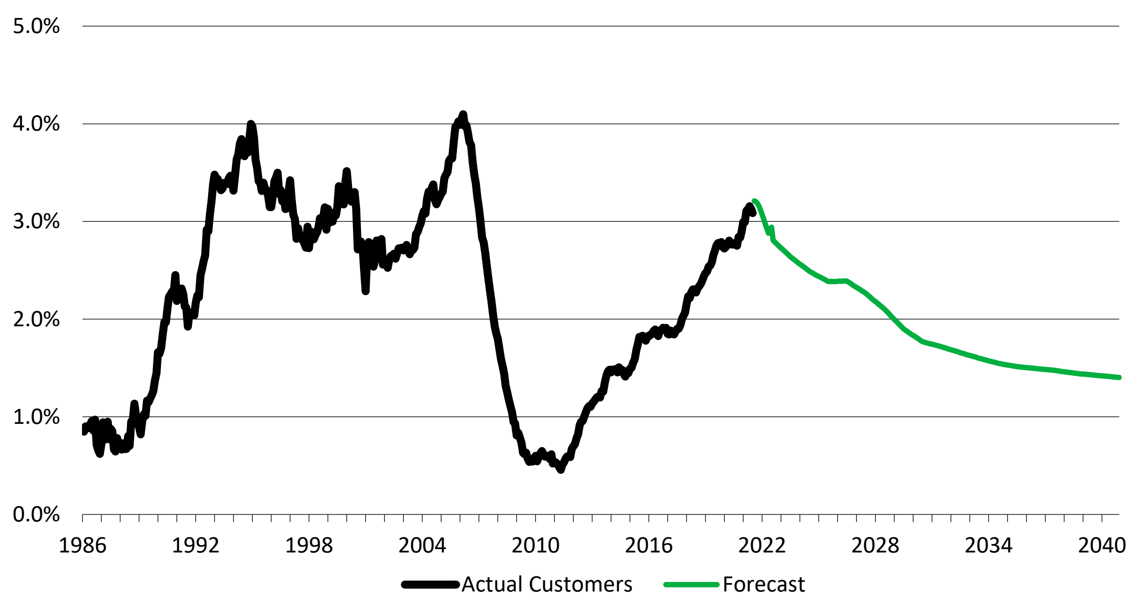

Figure 9. **Residential customer growth rates (12-month change)**

Final sales to residential retail customers can be framed in 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 using a statistically adjusted end-use (SAE) forecast model as described above that is used in Idaho Power's forecast residential sales is provided in Figure 10.

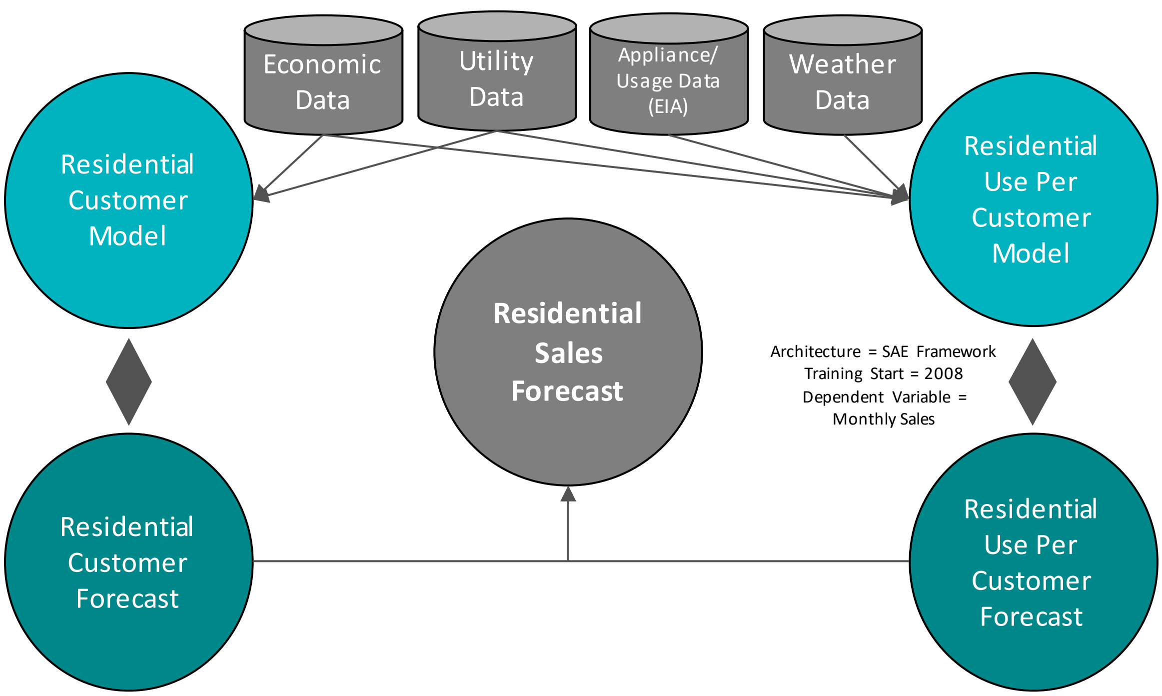

Figure 10. Residential sales forecast methodology framework

Further, there were several instances in the SAE framework where the overall outcomes could benefit from the inclusion of indicator variables. In assessing these and combination thereof, Idaho Power selected the best statistical result across a menu of options using cross validation methods.

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 anticipated scenario, the commercial load is projected to increase from 475 aMW in 2021 to 564 aMW in 2040 (Table 8). The average annual compound-growth rate of the commercial load in the anticipated scenario is 0.9% during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 481 aMW in 2021 to 572 aMW in 2040. The commercial load forecast scenarios are illustrated in Figure 11.

Table 8. Commercial load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	489	515	535	585	0.9%
70th Percentile	481	505	524	572	0.9%
Anticipated Case	475	499	517	564	0.9%

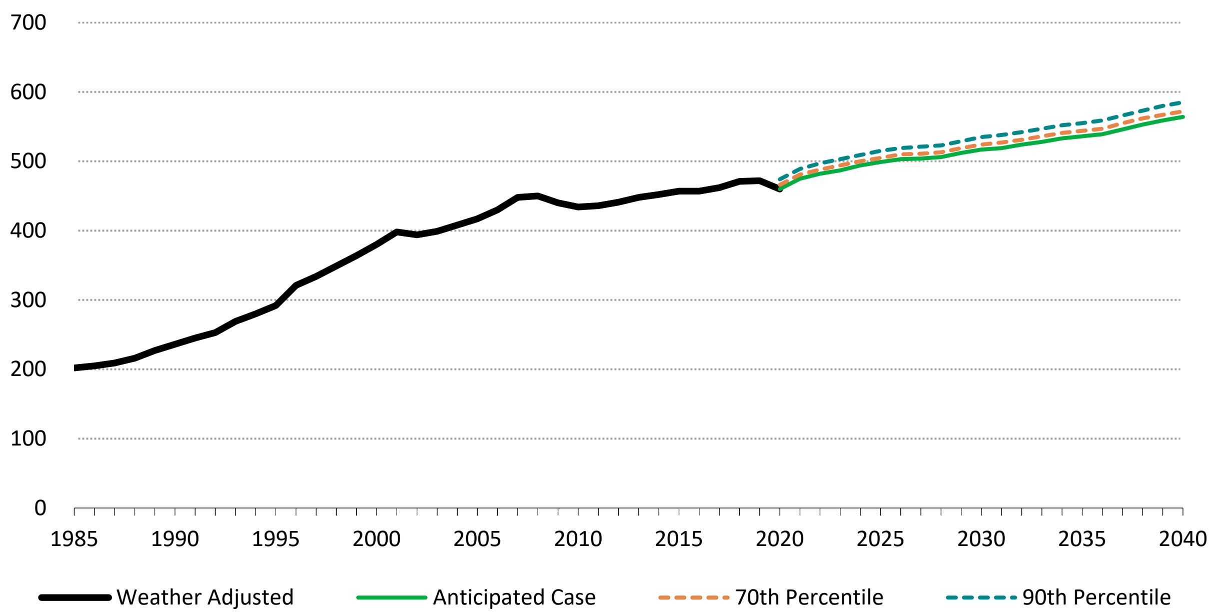

Figure 11. Forecast commercial load (aMW)

With a customer base of over 75,500, 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—for analytical purposes—the category is 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 2020 billed energy sales.

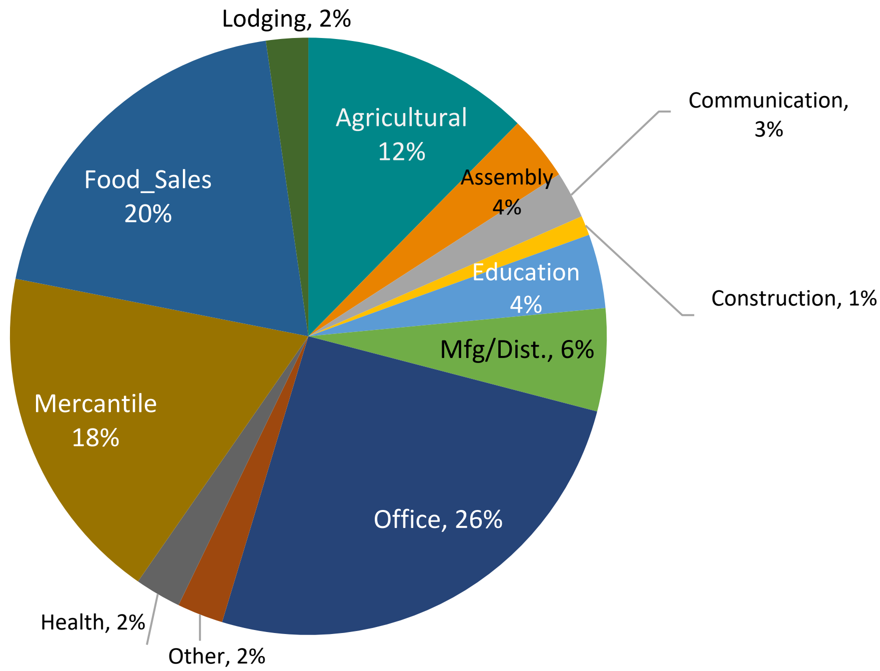

Figure 12. Commercial building share—energy bills

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 around lighting). Categories showing significant growth over the past 5 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 energy use grow by 10% per year. Agricultural and manufacturing operations continue to migrate and flourish with growth rates of 2.2% and 2.5% respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.8%, reaching approximately 107,000 customers by December 2040.

In 1990, customers in the commercial category consumed approximately 18% of Idaho Power system sales, growing to 27% by 2020. 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 67,800 kWh and has declined at approximately 1.1% compounded annually to 2020. The UPC is forecast to decrease at an annual rate of 0.9% over the planning period. For this category, common elements that drive use down include a shift toward service-based over industrial customer dominance, adoption of energy efficiency technology, and electricity prices.

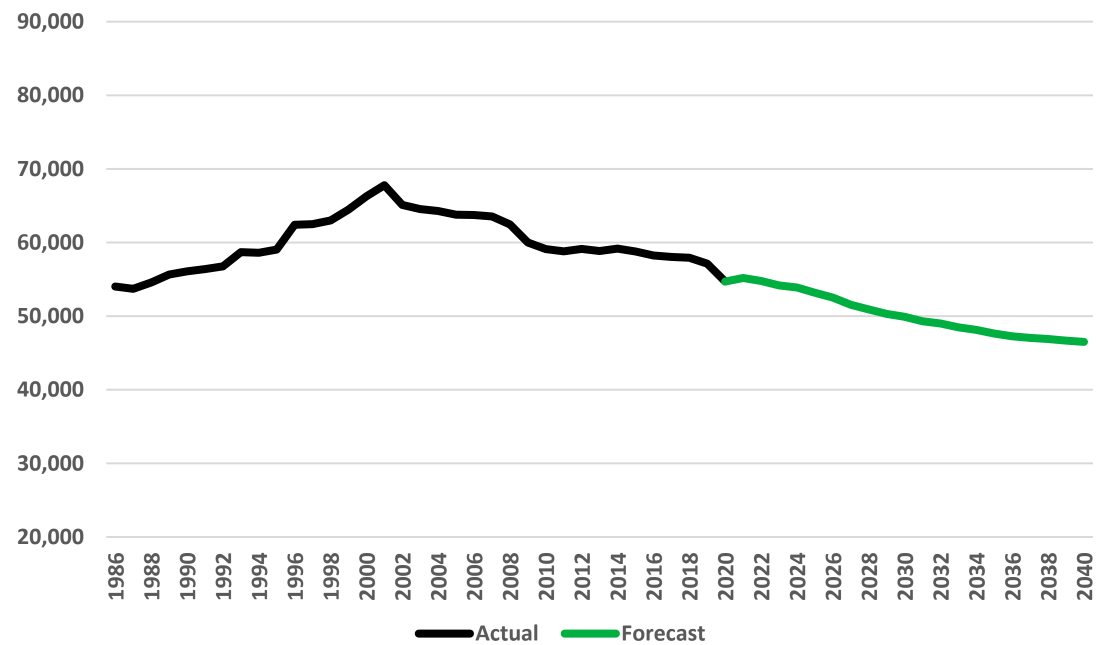

Figure 13. Forecast commercial use per customer (weather-adjusted kWh)

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2020 UPC for each segment relative to the 2013 UPC. A value greater than 100% 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. The decline in Figure 14 is also significantly exacerbated by the COVID-19 crisis, which saw many commercial customer segments close or significantly limit operations during 2020. The subsequent reduction in energy use during this period varied by segment, however they were concentrated in the service-oriented customers—particularly Education, Office, Lodging, Restaurant, and Mercantile segments. The models and independent analysis have shown a significant and ongoing rebound to normal energy use profiles in 2021 for the commercial sector. The recovery is expected to be complete by the first quarter of 2022.

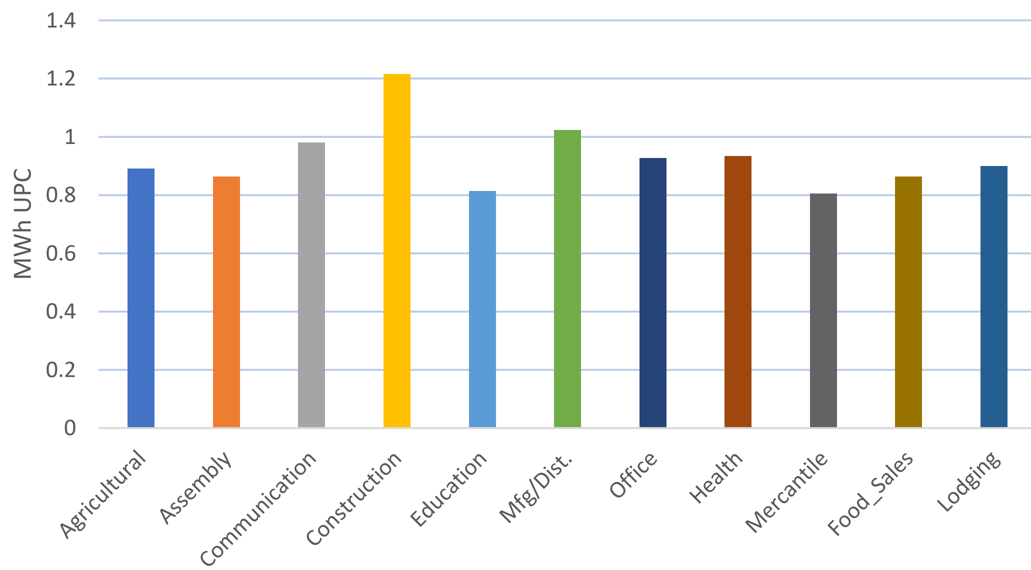

Figure 14. Commercial categories UPC, 2020 relative to 2013

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, however manufacturing motors are significant for that sector. Understandably, aggressive DSM measures can reduce a customer’s usage to trigger a rate-class change from industrial to commercial class. These shifts are evident in the chart (COVID notwithstanding) with the most aggressive DSM implementation categories of Education and Food Sales. 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. Tariff migration occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial). Note that the forecast models aggregate the energy use of these two schedules to mitigate this influence.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the category. Typical variables include corporate earnings; government spending; wholesale/retail trade; 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% of Idaho Power's system sales. By December 2020, the number of industrial customers had risen to 123, representing approximately 17% of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration to and from the commercial class as dictated by the tariff rules. However, 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 anticipated forecast, industrial load grows from 295 aMW in 2021 to 397 aMW in 2040, an average annual growth rate of 1.6% (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 anticipated industrial load scenario. The industrial load forecast is pictured in Figure 15.

Table 9. Industrial load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Anticipated Case	295	332	351	397	1.6%

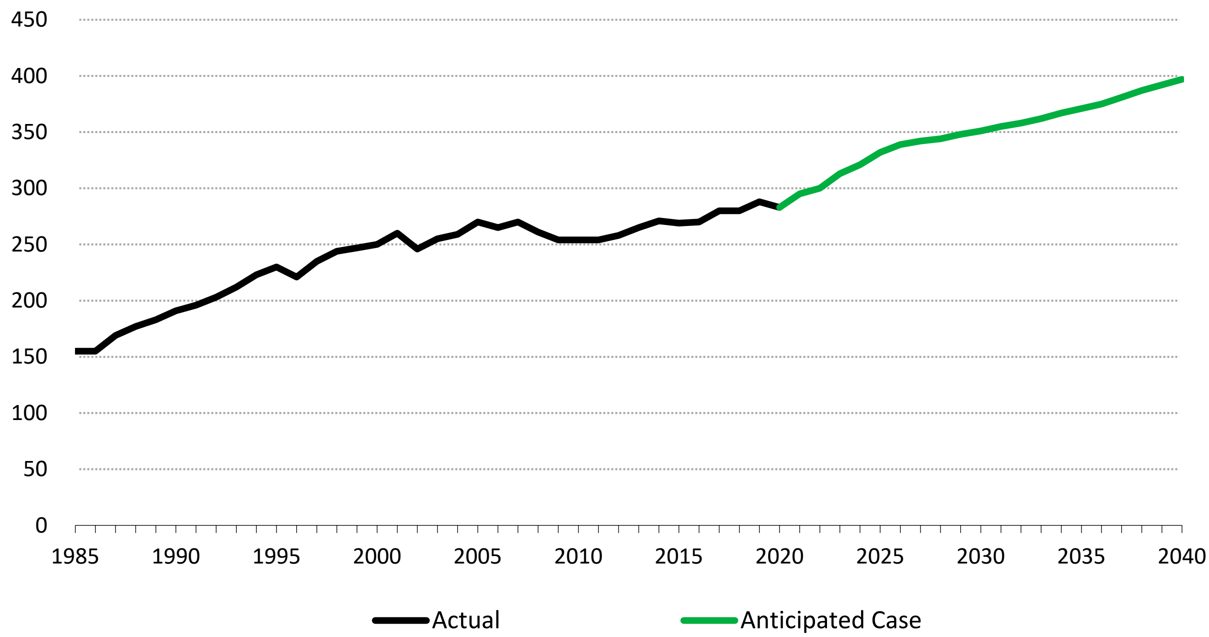

Figure 15. Forecast industrial load (aMW)

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 are 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 2020 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%), followed by dairy (18%) and construction-related (7%). The categorization scheme includes a range of service-providing 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.

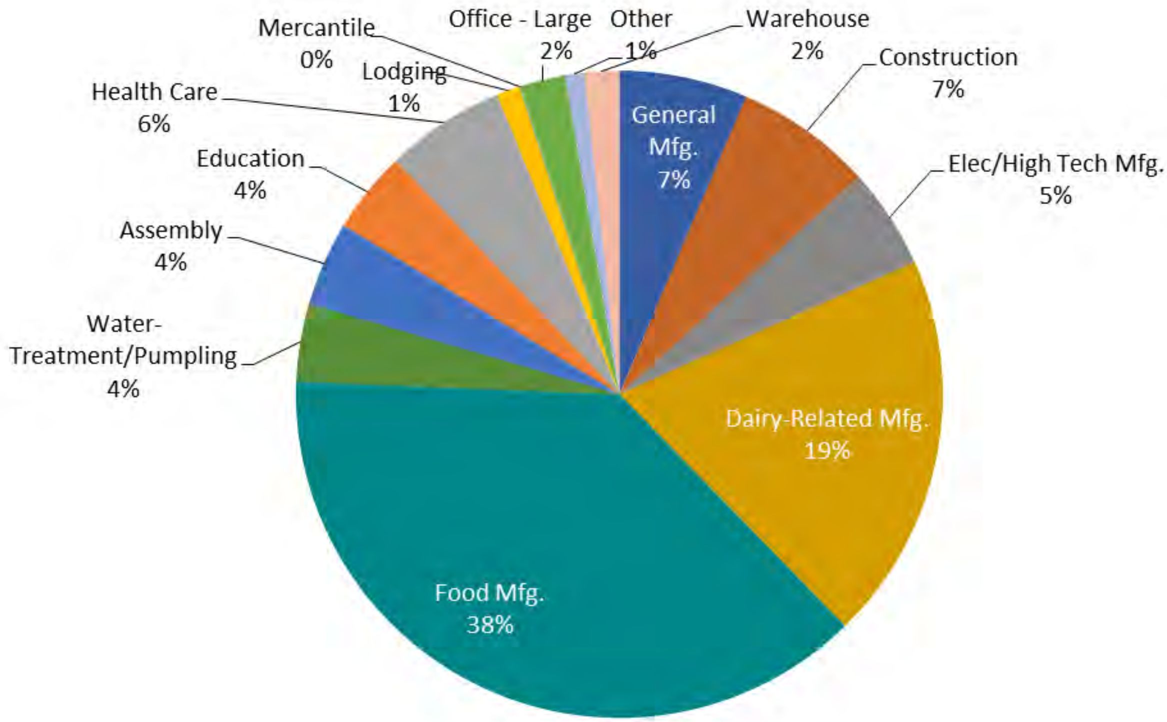

Figure 16. **Industrial electricity consumption by industry group (based on 2020 sales)**

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and variables such as, corporate earnings, 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 previously excluded DSM is subtracted. Figure 17 shows the general forecasting methodology used for both the commercial and industrial sectors.

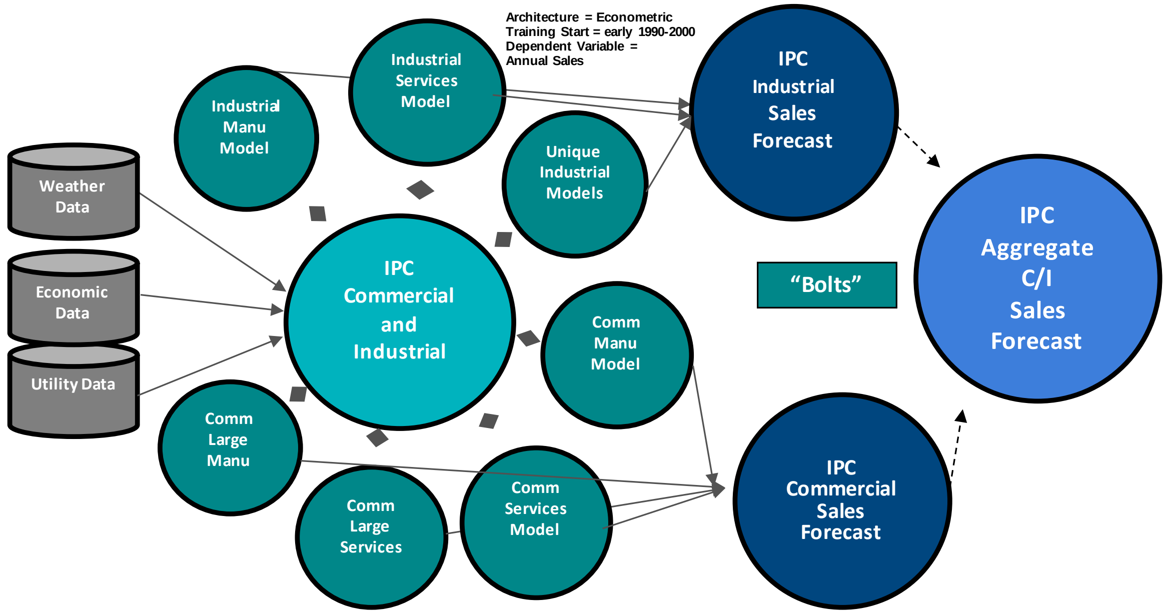

Figure 17. Commercial and industrial general sales forecast methodology

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 anticipated irrigation load is forecast to increase slowly from 225 aMW in 2021 to 250 aMW in 2040, an average annual compound growth rate of 0.6%. In the 70th-percentile scenario, irrigation load is projected to be 241 aMW in 2021 and 266 aMW in 2040. The anticipated, 70th-percentile, and 90th-percentile scenarios forecast slower growth than the system in irrigation load from 2021 to 2040. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

Table 10. Irrigation load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	261	265	270	286	0.5%
70th Percentile	241	244	250	266	0.5%
Anticipated Case	225	229	234	250	0.6%

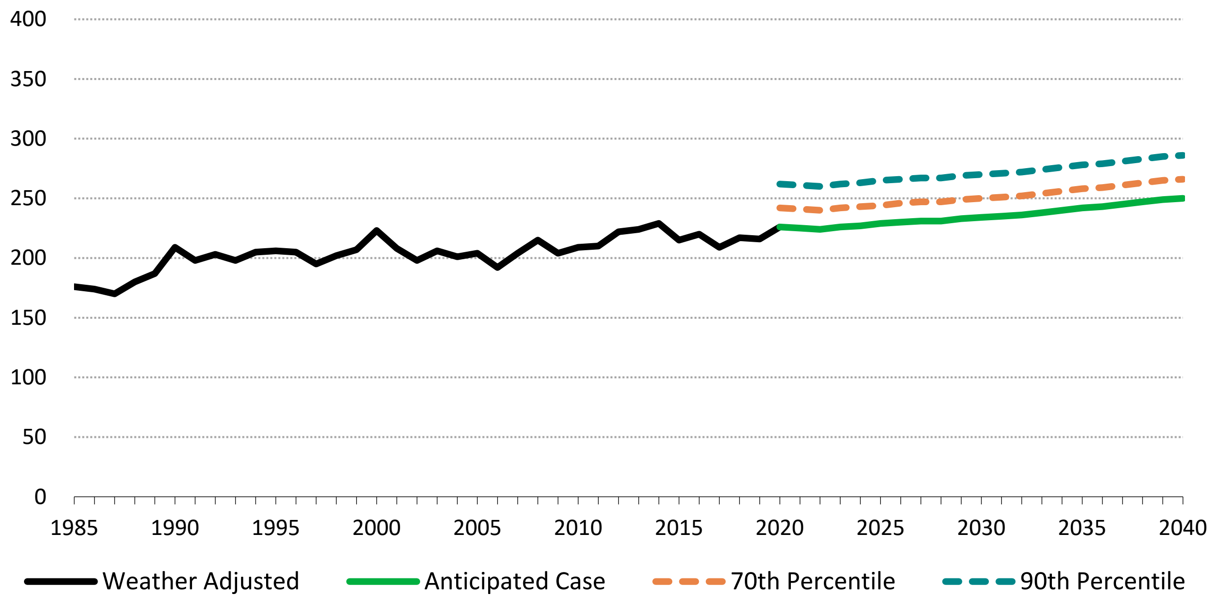

Figure 18. **Forecast irrigation load (aMW)**

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% 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% of the energy consumed during the hour of the annual system peak and nearly 30% 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 2021 IRP irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; 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 MWh to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20% of Idaho Power system sales. In 2020, the irrigation proportion of system sales was 13% 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 2020, the number of active irrigation accounts had increased to 20,800 and is projected to be nearly 25,800 at the end of the planning period in 2040.

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); the Idaho National Laboratory (INL); and any anticipated special contract customer(s) at the time. These special-contract customers comprise the forecast category labeled additional firm load.

In the anticipated forecast, additional firm load is expected to increase from 108 aMW in 2021 to 345 aMW in 2040, an average growth rate of 6.3% per year over the planning period (Table 11). The additional firm load energy and demand forecasts in the 70th- and 90th-percentile scenarios are identical to the anticipated-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 19.

Table 11. Additional firm load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Anticipated Case	108	195	345	345	6.3%

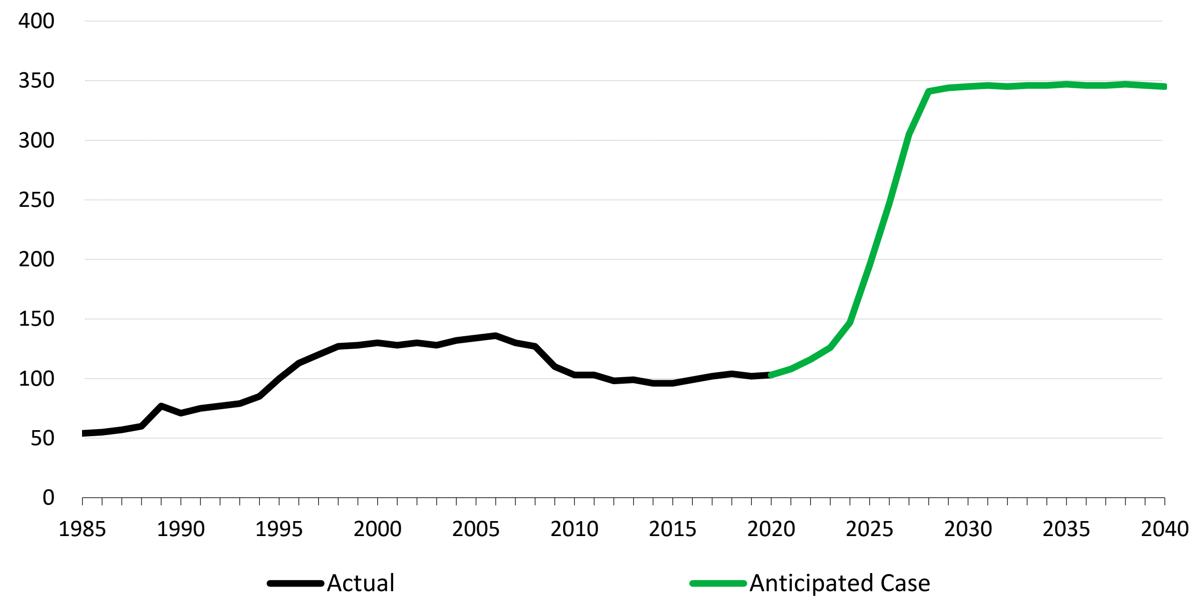

Figure 19. **Forecast additional firm load (aMW)**

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000–6,000 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

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

Idaho National Laboratory

Idaho National Laboratory (INL) is one of the United States Department of Energy's (DOE) national laboratories and is the nation's lead laboratory for nuclear energy research, development, and demonstration. The DOE, in partnership with its contractors, is focused on performing research and development in energy programs and national defense. Much of the work to achieve this mission at INL is performed in government-owned and leased buildings on the Research and Education Campus (REC) 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 employees estimated at 4,225 workers.

Anticipated Large-Load Growth

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

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 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 from standard 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 over 1% 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, commercial, and irrigation 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, 2040, the annual residential sales forecast reduction was about 65 aMW, the commercial reduction was 3 aMW, and the irrigation reduction was 6 aMW.

Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While electric vehicle (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. Idaho Power receives detailed registration data from Idaho Transportation Department (ITD). The data provides county-level registration which provides a basis for determining Idaho Power 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 United States 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). Idaho Power 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 Idaho Power forecast for PEVs shows that the service territory will continue to fall into the lower adoption ranges. Idaho Power 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 2020 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 (2021–2040) (average annual percent change)

	Nominal	Real*
Electricity—2021 IRP	1.0%	-1.3%
Electricity—2019 IRP	1.1%	-1.1%
Natural Gas	2.2%	0.0%

* Adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1985 to 2020 and over the forecast period 2021 to 2040.
Both nominal and real prices are shown. In the 2021 IRP, nominal electricity prices are expected to climb to about 12.5 cents per kWh by the end of the forecast period in 2040. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 1.3% annually. In the 2019 IRP, nominal electricity prices were assumed to climb to about 14 cents per kWh by 2040, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of 1.1% annually.

The electricity price forecast used to prepare the sales and load forecast in the 2021 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price forecast yields lower future prices. The retail prices are mostly lower throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

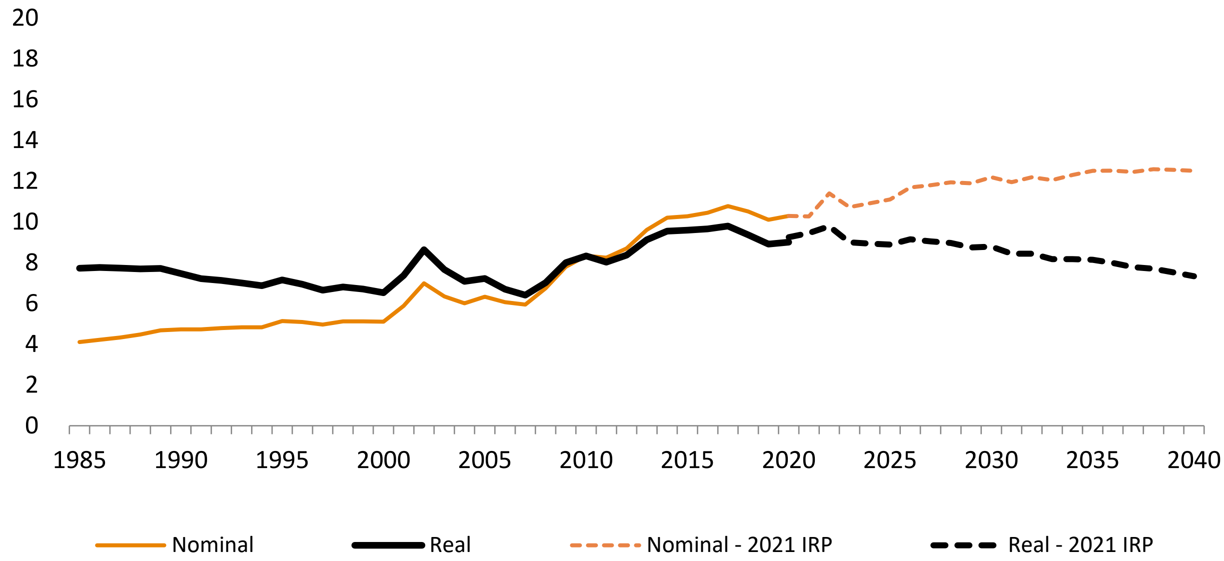

Figure 20. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002, a direct result of the western United States 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% overall, an annual average compound growth rate of 0.8% annually. In contrast, from 2000 to 2010, nominal electricity prices rose 63% overall, an annual average compound growth rate of 4.2% annually. More recently, over the period 2010 to 2020, nominal electricity prices rose 23% overall, an annual average compound growth rate of 1.8% annually.

Figure 21 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1985 to 2020 and forecast prices from 2020 to 2040. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. After 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 by 47%, compared to 2020. Nominal natural gas prices are initially expected to remain relatively flat through 2022, drop in 2023, and then rise at a steady pace throughout the remainder of the forecast period, increasing 70% by 2040, growing at an average rate of 2.2% per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0% annually.

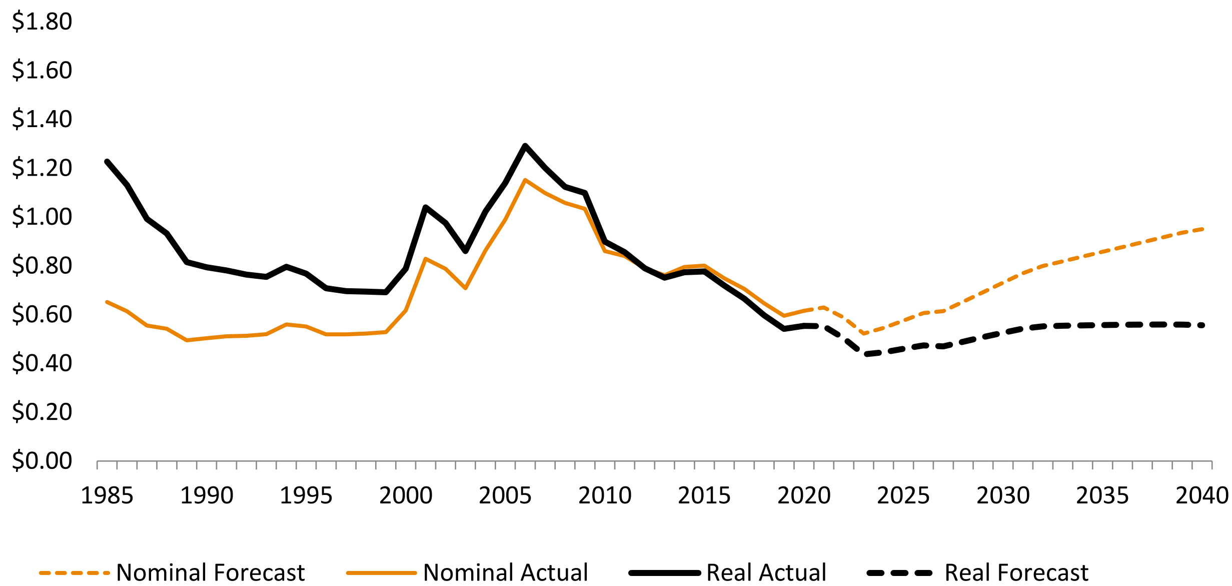

Figure 21. Forecast residential natural gas prices (dollars per therm)

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. S&P Global Platts provides the forecasts of long-term changes in nominal natural gas prices. In the 2021 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 downward in the near term through 2023, with prices slowly rising throughout the forecast period after that.

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 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 2021 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 and 2019 IRPs, Idaho Power has leveraged several years of advanced metering infrastructure (AMI) data to adopt a new hourly load forecasting methodology to be used in the 2021 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.

2021 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 a new methodology could be developed 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 Itron Forecasting. 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.

The above process can be repeated for each major customer class to produce estimated contributions to system peak by customer class as can be seen in Figure 22.

Figure 22. Class Contribution to System Peak

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. Currently, 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, 1980–2020 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	7,866		974
1981	8,181	4.0%	1,014
1982	7,822	-4.4%	973
1983	8,034	2.7%	998
1984	8,120	1.1%	1,006
1985	8,262	1.7%	1,026
1986	8,346	1.0%	1,037
1987	8,489	1.7%	1,055
1988	8,832	4.0%	1,094
1989	9,203	4.2%	1,143
1990	9,575	4.0%	1,189
1991	9,749	1.8%	1,210
1992	9,973	2.3%	1,235
1993	10,268	3.0%	1,276
1994	10,676	4.0%	1,326
1995	11,140	4.4%	1,381
1996	11,479	3.0%	1,421
1997	11,770	2.5%	1,460
1998	12,261	4.2%	1,519
1999	12,558	2.4%	1,557
2000	12,951	3.1%	1,604
2001	13,089	1.1%	1,618
2002	12,791	-2.3%	1,587
2003	13,131	2.7%	1,627
2004	13,362	1.8%	1,655
2005	13,721	2.7%	1,705
2006	13,994	2.0%	1,735
2007	14,386	2.8%	1,785
2008	14,490	0.7%	1,789
2009	14,010	-3.3%	1,738
2010	13,876	-1.0%	1,720
2011	13,908	0.2%	1,724
2012	14,093	1.3%	1,742

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	14,101	0.1%	1,756
2014	14,283	1.3%	1,768
2015	14,131	-1.1%	1,753
2016	14,300	1.2%	1,773
2017	14,422	0.8%	1,788
2018	14,605	1.3%	1,813
2019	14,762	1.1%	1,834
2020	14,928	1.1%	1,856

Company System Load

Projected Company System Sales and Load, 2021–2040

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	15,283	2.4%	1,895
2022	15,528	1.6%	1,926
2023	15,845	2.0%	1,965
2024	16,175	2.1%	2,008
2025	16,338	1.0%	2,082
2026	16,587	1.5%	2,154
2027	16,761	1.1%	2,223
2028	16,889	0.8%	2,269
2029	16,996	0.6%	2,289
2030	17,117	0.7%	2,304
2031	17,199	0.5%	2,314
2032	17,314	0.7%	2,322
2033	17,396	0.5%	2,338
2034	17,535	0.8%	2,356
2035	17,686	0.9%	2,375
2036	17,848	0.9%	2,389
2037	18,030	1.0%	2,418
2038	18,231	1.1%	2,442
2039	18,404	0.9%	2,464
2040	18,604	1.1%	2,482

Residential Load

Historical Residential Sales and Load, 1980–2020 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	209,629		14,771	3,096		353
1981	213,579	1.9%	14,748	3,150	1.7%	355
1982	216,696	1.5%	13,562	2,939	-6.7%	337
1983	219,849	1.5%	14,321	3,149	7.1%	358
1984	222,695	1.3%	14,031	3,125	-0.8%	355
1985	225,185	1.1%	13,867	3,123	-0.1%	356
1986	227,081	0.8%	14,028	3,186	2.0%	365
1987	228,868	0.8%	13,970	3,197	0.4%	366
1988	230,771	0.8%	14,232	3,284	2.7%	375
1989	233,370	1.1%	14,217	3,318	1.0%	380
1990	238,117	2.0%	14,261	3,396	2.3%	388
1991	243,207	2.1%	14,373	3,496	2.9%	401
1992	249,767	2.7%	14,104	3,523	0.8%	401
1993	258,271	3.4%	14,088	3,638	3.3%	417
1994	267,854	3.7%	14,008	3,752	3.1%	429
1995	277,131	3.5%	14,024	3,887	3.6%	444
1996	286,227	3.3%	13,794	3,948	1.6%	451
1997	294,674	3.0%	13,728	4,045	2.5%	462
1998	303,300	2.9%	13,791	4,183	3.4%	478
1999	312,901	3.2%	13,654	4,272	2.1%	488
2000	322,402	3.0%	13,442	4,334	1.4%	494
2001	331,009	2.7%	13,210	4,373	0.9%	498
2002	339,764	2.6%	12,708	4,318	-1.3%	495
2003	349,219	2.8%	12,817	4,476	3.7%	511
2004	360,462	3.2%	12,755	4,598	2.7%	525
2005	373,602	3.6%	12,752	4,764	3.6%	547
2006	387,707	3.8%	12,992	5,037	5.7%	576
2007	397,286	2.5%	13,024	5,174	2.7%	591
2008	402,520	1.3%	12,942	5,209	0.7%	593
2009	405,144	0.7%	12,786	5,180	-0.6%	590
2010	407,551	0.6%	12,524	5,104	-1.5%	583
2011	409,786	0.5%	12,485	5,116	0.2%	583
2012	413,610	0.9%	12,403	5,130	0.3%	583
2013	418,892	1.3%	12,069	5,055	-1.5%	581
2014	425,036	1.5%	11,996	5,099	0.9%	579

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	432,275	1.7%	11,691	5,054	-0.9%	577
2016	440,362	1.9%	11,642	5,127	1.4%	585
2017	448,800	1.9%	11,552	5,184	1.1%	592
2018	459,128	2.3%	11,385	5,227	0.8%	596
2019	471,298	2.7%	11,287	5,320	1.8%	609
2020	484,433	2.8%	11,450	5,547	4.3%	637

Projected Residential Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	499,559	3.1%	11,281	5,636	1.6%	644
2022	513,957	2.9%	11,110	5,710	1.3%	652
2023	527,572	2.6%	10,941	5,772	1.1%	660
2024	540,764	2.5%	10,789	5,834	1.1%	665
2025	553,746	2.4%	10,591	5,865	0.5%	670
2026	566,899	2.4%	10,405	5,898	0.6%	674
2027	579,731	2.3%	10,231	5,931	0.6%	678
2028	591,914	2.1%	10,082	5,968	0.6%	680
2029	603,243	1.9%	9,945	5,999	0.5%	685
2030	613,993	1.8%	9,803	6,019	0.3%	687
2031	624,544	1.7%	9,669	6,039	0.3%	690
2032	634,909	1.7%	9,534	6,053	0.2%	689
2033	645,083	1.6%	9,396	6,062	0.1%	692
2034	655,094	1.6%	9,319	6,105	0.7%	697
2035	665,028	1.5%	9,274	6,168	1.0%	705
2036	674,971	1.5%	9,237	6,235	1.1%	710
2037	684,927	1.5%	9,209	6,308	1.2%	721
2038	694,856	1.4%	9,180	6,379	1.1%	729
2039	704,784	1.4%	9,154	6,451	1.1%	737
2040	714,731	1.4%	9,129	6,524	1.1%	743

Commercial Load

Historical Commercial Sales and Load, 1980–2020 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	28,797		54,184	1,560		178
1981	29,567	2.7%	54,326	1,606	2.9%	184
1982	30,167	2.0%	54,147	1,633	1.7%	186
1983	30,776	2.0%	52,643	1,620	-0.8%	185
1984	31,554	2.5%	53,824	1,698	4.8%	194
1985	32,418	2.7%	54,495	1,767	4.0%	202
1986	33,208	2.4%	54,027	1,794	1.6%	205
1987	33,975	2.3%	53,710	1,825	1.7%	209
1988	34,723	2.2%	54,567	1,895	3.8%	216
1989	35,638	2.6%	55,654	1,983	4.7%	227
1990	36,785	3.2%	56,088	2,063	4.0%	236
1991	37,922	3.1%	56,385	2,138	3.6%	245
1992	39,022	2.9%	56,761	2,215	3.6%	253
1993	40,047	2.6%	58,693	2,350	6.1%	269
1994	41,629	4.0%	58,612	2,440	3.8%	280
1995	43,165	3.7%	59,035	2,548	4.4%	292
1996	44,995	4.2%	62,399	2,808	10.2%	321
1997	46,819	4.1%	62,490	2,926	4.2%	334
1998	48,404	3.4%	62,989	3,049	4.2%	349
1999	49,430	2.1%	64,468	3,187	4.5%	364
2000	50,117	1.4%	66,281	3,322	4.2%	380
2001	51,501	2.8%	67,783	3,491	5.1%	398
2002	52,915	2.7%	65,108	3,445	-1.3%	394
2003	54,194	2.4%	64,529	3,497	1.5%	399
2004	55,577	2.6%	64,280	3,573	2.2%	408
2005	57,145	2.8%	63,785	3,645	2.0%	417
2006	59,050	3.3%	63,731	3,763	3.2%	430
2007	61,640	4.4%	63,533	3,916	4.1%	448
2008	63,492	3.0%	62,458	3,966	1.3%	450
2009	64,151	1.0%	59,998	3,849	-2.9%	440
2010	64,421	0.4%	59,098	3,807	-1.1%	434
2011	64,921	0.8%	58,806	3,818	0.3%	436
2012	65,599	1.0%	59,128	3,879	1.6%	441
2013	66,357	1.2%	58,834	3,904	0.7%	448
2014	67,113	1.1%	59,173	3,971	1.7%	452

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	68,000	1.3%	58,772	3,996	0.6%	457
2016	68,883	1.3%	58,226	4,011	0.4%	457
2017	69,850	1.4%	58,031	4,053	1.1%	462
2018	71,104	1.8%	57,942	4,120	1.6%	471
2019	72,332	1.7%	57,126	4,132	0.3%	472
2020	73,703	1.9%	54,687	4,031	-2.5%	460

Projected Commercial Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	75,289	2.2%	55,179	4,154	3.1%	475
2022	76,982	2.2%	54,790	4,218	1.5%	482
2023	78,717	2.3%	54,161	4,263	1.1%	487
2024	80,420	2.2%	53,893	4,334	1.7%	494
2025	82,123	2.1%	53,161	4,366	0.7%	499
2026	83,847	2.1%	52,530	4,404	0.9%	503
2027	85,591	2.1%	51,550	4,412	0.2%	504
2028	87,323	2.0%	50,905	4,445	0.7%	506
2029	89,008	1.9%	50,313	4,478	0.7%	512
2030	90,638	1.8%	49,915	4,524	1.0%	517
2031	92,235	1.8%	49,301	4,547	0.5%	519
2032	93,818	1.7%	49,004	4,597	1.1%	524
2033	95,394	1.7%	48,471	4,624	0.6%	528
2034	96,961	1.6%	48,127	4,666	0.9%	533
2035	98,524	1.6%	47,622	4,692	0.5%	536
2036	100,086	1.6%	47,267	4,731	0.8%	539
2037	101,652	1.6%	47,034	4,781	1.1%	546
2038	103,220	1.5%	46,896	4,841	1.2%	553
2039	104,791	1.5%	46,674	4,891	1.0%	559
2040	106,365	1.5%	46,508	4,947	1.1%	564

Irrigation Load

Historical Irrigation Sales and Load, 1980–2020 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	10,854		160,699	1,744		199
1981	11,248	3.6%	168,950	1,900	9.0%	217
1982	11,312	0.6%	152,063	1,720	-9.5%	197
1983	11,133	-1.6%	147,885	1,646	-4.3%	188
1984	11,375	2.2%	136,181	1,549	-5.9%	176
1985	11,576	1.8%	133,372	1,544	-0.3%	176
1986	11,308	-2.3%	135,042	1,527	-1.1%	174
1987	11,254	-0.5%	132,422	1,490	-2.4%	170
1988	11,378	1.1%	138,605	1,577	5.8%	180
1989	11,957	5.1%	136,898	1,637	3.8%	187
1990	12,340	3.2%	148,190	1,829	11.7%	209
1991	12,484	1.2%	139,041	1,736	-5.1%	198
1992	12,809	2.6%	139,340	1,785	2.8%	203
1993	13,078	2.1%	132,733	1,736	-2.7%	198
1994	13,559	3.7%	132,365	1,795	3.4%	205
1995	13,679	0.9%	132,064	1,807	0.7%	206
1996	14,074	2.9%	127,939	1,801	-0.3%	205
1997	14,383	2.2%	118,804	1,709	-5.1%	195
1998	14,695	2.2%	120,611	1,772	3.7%	202
1999	14,912	1.5%	121,861	1,817	2.5%	207
2000	15,253	2.3%	128,582	1,961	7.9%	223
2001	15,522	1.8%	117,166	1,819	-7.3%	208
2002	15,840	2.0%	109,361	1,732	-4.7%	198
2003	16,020	1.1%	112,556	1,803	4.1%	206
2004	16,297	1.7%	108,438	1,767	-2.0%	201
2005	16,936	3.9%	105,450	1,786	1.1%	204
2006	17,062	0.7%	98,468	1,680	-5.9%	192
2007	17,001	-0.4%	105,169	1,788	6.4%	204
2008	17,428	2.5%	108,589	1,892	5.8%	215
2009	17,708	1.6%	101,150	1,791	-5.4%	204
2010	17,846	0.8%	102,345	1,826	2.0%	209

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2011	18,292	2.5%	100,456	1,838	0.6%	210
2012	18,675	2.1%	104,483	1,951	6.2%	222
2013	19,017	1.8%	103,133	1,961	0.5%	224
2014	19,328	1.6%	103,920	2,009	2.4%	229
2015	19,756	2.2%	95,126	1,879	-6.4%	215
2016	20,042	1.4%	96,382	1,932	2.8%	220
2017	20,246	1.0%	90,552	1,833	-5.1%	209
2018	20,459	1.1%	92,940	1,901	3.7%	217
2019	20,566	0.5%	92,107	1,894	-0.4%	216
2020	20,804	1.2%	95,385	1,984	4.8%	226

Projected Irrigation Sales and Load, 2021–2040

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	21,063	1.2%	93,540	1,970	-0.7%	225
2022	21,290	1.1%	92,318	1,965	-0.2%	224
2023	21,538	1.2%	92,090	1,983	0.9%	226
2024	21,786	1.2%	91,540	1,994	0.5%	227
2025	22,035	1.1%	90,887	2,003	0.4%	229
2026	22,283	1.1%	90,320	2,013	0.5%	230
2027	22,531	1.1%	89,780	2,023	0.5%	231
2028	22,782	1.1%	89,216	2,033	0.5%	231
2029	23,028	1.1%	88,648	2,041	0.4%	233
2030	23,278	1.1%	88,097	2,051	0.5%	234
2031	23,527	1.1%	87,552	2,060	0.4%	235
2032	23,774	1.0%	87,170	2,072	0.6%	236
2033	24,024	1.1%	86,879	2,087	0.7%	238
2034	24,274	1.0%	86,599	2,102	0.7%	240
2035	24,522	1.0%	86,333	2,117	0.7%	242
2036	24,770	1.0%	86,082	2,132	0.7%	243
2037	25,020	1.0%	85,852	2,148	0.7%	245
2038	25,267	1.0%	85,634	2,164	0.7%	247
2039	25,515	1.0%	85,457	2,180	0.8%	249
2040	25,763	1.0%	85,311	2,198	0.8%	250

Industrial Load

Historical Industrial Sales and Load, 1980–2020 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	112		9,894,706	1,106		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

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
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%	21,274,929	2,447	-0.3%	280
2019	124	8.0%	20,288,866	2,521	3.0%	288

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2020	124	-0.3%	19,912,671	2,466	-2.2%	283

Projected Industrial Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	124	-0.2%	20,879,623	2,580	4.6%	295
2022	123	-0.5%	21,326,834	2,623	1.7%	300
2023	123	0.0%	22,198,824	2,730	4.1%	313
2024	125	1.6%	22,532,633	2,817	3.2%	321
2025	126	0.8%	22,993,784	2,897	2.9%	332
2026	126	0.0%	23,539,107	2,966	2.4%	339
2027	126	0.0%	23,746,821	2,992	0.9%	342
2028	129	2.4%	23,388,087	3,017	0.8%	344
2029	130	0.8%	23,420,860	3,045	0.9%	348
2030	130	0.0%	23,653,746	3,075	1.0%	351
2031	130	0.0%	23,868,001	3,103	0.9%	355
2032	132	1.5%	23,787,633	3,140	1.2%	358
2033	133	0.8%	23,849,695	3,172	1.0%	362
2034	133	0.0%	24,135,122	3,210	1.2%	367
2035	133	0.0%	24,409,273	3,246	1.1%	371
2036	135	1.5%	24,355,460	3,288	1.3%	375
2037	135	0.0%	24,705,719	3,335	1.4%	381
2038	135	0.0%	25,098,479	3,388	1.6%	387
2039	135	0.0%	25,405,447	3,430	1.2%	392
2040	137	1.5%	25,425,088	3,483	1.6%	397

Additional Firm Sales and Load

Historical Additional Firm Sales and Load, 1980–2020

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	360		41
1981	376	4.6%	43
1982	367	-2.4%	42
1983	425	15.7%	49
1984	466	9.7%	53
1985	471	1.1%	54
1986	482	2.4%	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	740	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	1,121	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

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	842	0.1%	96
2016	870	3.3%	99
2017	897	3.1%	102
2018	910	1.4%	104
2019	895	-1.7%	102
2020	900	0.6%	103

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

Projected Additional Firm Sales and Load, 2021–2040

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	943	4.7%	108
2022	1,019	8.1%	116
2023	1,104	8.4%	126
2024	1,288	16.7%	147
2025	1,706	32.4%	195
2026	2,163	26.8%	247
2027	2,668	23.3%	305
2028	2,996	12.3%	341
2029	3,010	0.4%	344
2030	3,025	0.5%	345
2031	3,027	0.1%	346
2032	3,032	0.2%	345
2033	3,028	-0.1%	346
2034	3,029	0.0%	346
2035	3,040	0.4%	347
2036	3,043	0.1%	346
2037	3,035	-0.3%	346
2038	3,036	0.0%	347
2039	3,028	-0.3%	346
2040	3,032	0.1%	345

*Includes Micron Technology, Simplot Fertilizer, the INL, and any anticipated special contract customers

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2021 IRP

INTEGRATED RESOURCE PLAN

A VIEW FROM ABOVE

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.

Idaho Power's portfolio of energy efficiency program savings remained strong in 2020 with the second highest savings since the Idaho Energy Efficiency Rider (Idaho Rider) began in 2002. This was accomplished even though many programs were affected by COVID-19 restrictions. The 2020 savings of 196,809 megawatt-hour (MWh), including the estimated savings from the Northwest Energy Efficiency Alliance (NEEA), decreased by 6,493 MWh compared to the 2019 savings of 203,302 MWh—a 3% year-over-year decrease. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, was 180,818 MWh in 2020 and 184,934 MWh in 2019—a 2% year-over-year decrease. The 2020 savings represent enough energy to power almost 17,000 average homes in Idaho Power's service area for one year.

In 2020, 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 2.08 and 2.71, respectively. The portfolio was also cost-effective from the participant cost test (PCT) ratio, which was 2.45.

Idaho Power successfully operated all three of its demand response programs in 2020. The total demand response capacity from the company's programs was 366 megawatts (MW) with actual load reduction of 336 MW. Energy efficiency and demand response are important aspects of Idaho Power's resource planning process and were included in the 2019 IRP.

Total expenditures from all funding sources of demand-side management (DSM) activities were $50.6 million in 2020—$40.4 million from the Idaho Rider, $8.4 million from Idaho Power base rates, and $1.8 million from the Oregon Rider. DSM program funding comes from the Idaho and Oregon Riders, Idaho Power base rates, and the annual power cost adjustment (PCA).

Idaho Power transitioned the Home Energy Report Pilot into a full program in June of 2020. On average, program participants are providing statistically significant savings at between 50 to 363 kWh fewer kWh annually per home than their control group counterparts. When viewed in aggregate, the estimated savings for all program participants was 10,428 MWh in 2020.

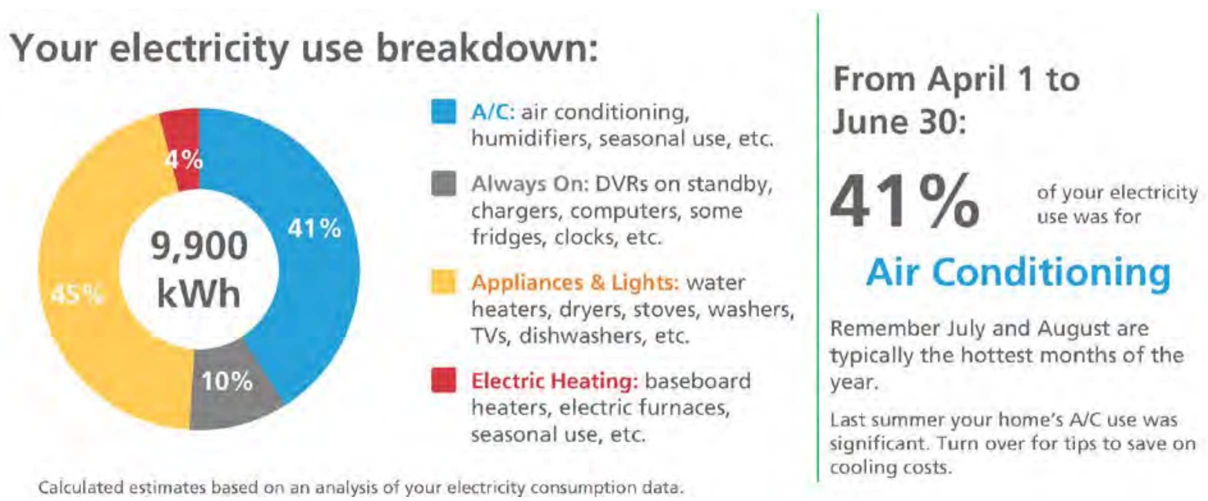

Figure 1. A portion of the Home Energy Report (HER) customers receive

Another way Idaho Power educated residential customers on energy savings related to energy-efficient behavior was to produce an *Energy Efficiency Guide* in 2020 with information on energy efficiency equipment and ways to use energy wisely. This guide was distributed in April primarily as an insert in 20 local newspapers. In 2020, despite the pandemic challenges, Idaho Power's education and outreach energy advisors (EOEA) delivered over 300 presentations with energy-savings messages to audiences of all ages.

In 2020, the Integrated Design Lab (IDL) scheduled 20 technical training lunches which were conducted virtually due to COVID-19 restrictions. Ten sessions were coordinated directly with architecture and engineering firms and organizations and ten were available to the public; a total of 366 architects, engineers, designers, project managers, and others attended.

The IDL also maintains an Energy Resource Library (ERL) with tools for measuring and monitoring energy use and provides training on how to use them. The library includes over 900 individual pieces of equipment, adding 34 new tools in 2020.

Idaho Power continued to provide training to its commercial and industrial customers in 2020, delivering equivalent of 5 full days of technical training over 12 virtual sessions.

Idaho Power provided five irrigation workshops and participated in two additional vendor hosted workshops promoting irrigation system efficiency. The company also participated in, and had an exhibit at, four agricultural trade shows prior to COVID-19 restrictions. The trade shows were the Idaho Irrigation Equipment Association Winter Show, Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, and the Agri Action Ag Show.

The company promotes significant customer educational, outreach and awareness activities, promotion of codes and standards, and marketing efforts that are not quantified or claimed as part of Idaho Power's annual DSM savings, but are likely to result in energy savings experienced by the customer and accruing to Idaho Power's electric system over time.

This *Demand-Side Management 2020 Annual Report* provides a review of the company's DSM activities and finances throughout 2020 and outlines Idaho Power's plans for future DSM activities. This report satisfies the reporting requirements set out in 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 UM 1710.

INTRODUCTION

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

In 2020, 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 how to participate in programs. This year was challenging due to COVID-19. However where possible, Idaho Power modified DSM activity to prioritize the safety of customers, contractors, and Idaho Power staff, while still balancing opportunities to maintain program performance. Idaho Power also worked with its Energy Efficiency Advisory Group (EEAG) to adjust programs impacted by COVID-19 and to identify opportunities for increased effectiveness in program delivery and marketing. Much of the company's customer in-home or on-location work was suspended in the early months of the pandemic. The company transitioned to virtual meetings, and leveraged technology to maintain participation. As state health and safety-guidelines were developed, some on-location work was able to resume at various businesses. The tables below summarize the status of individual programs and how they were affected by COVID-19 protocols.

Table 1. Impact of COVID-19 on residential programs

Programs	Status
A/C Cool Credit	Idaho Power reduced cycling %
Easy Savings: Low-Income Energy Efficiency Education	In-home work suspended
Energy Efficient Lighting	Program not affected
Energy House Calls	In-home work suspended
Energy-Saving Kits	Program not affected
Heating & Cooling Efficiency Program	Verifications conducted over the phone
Home Energy Audit Program	In-home work suspended
Home Energy Reports Program	Program not affected
Multifamily Energy Savings Program	In-home work suspended
Oregon Residential Weatherization	Audits resumed with customer approval
Rebate Advantage	Program not affected
Residential New Construction Program	Program not affected
Shade Tree Project	Public events postponed
Simple Steps, Smart Savings™	Program not affected
Student Energy Efficiency Kits (SEEK)	Program affected by school attendance & closures
Weatherization Assistance for Qualified Customers (WAQC)	State agencies resumed work early summer
Weatherization Solutions for Eligible Customers	In-home work suspended
Welcome Kits	Program not affected

Table 2. Impact of COVID-19 on commercial, industrial, and irrigation programs

Programs	Status
Commercial and Industrial (C&I) Custom Projects	On-location work affected
New Construction	Some on-location work affected
Retrofits	On-location work affected
Commercial Energy-Savings Kits	Program affected by small business closures
Flex Peak Program	Program affected by customer's ability to participate
Oregon Commercial Audits	On-location work suspended March-November
Small Business Direct Install	On-location work suspended March-October
Irrigation Efficiency Rewards—Custom	On-location work affected
Irrigation Efficiency Rewards—Menu	Program not affected
Irrigation Peak Rewards	Electrician work affected

This report focuses on Idaho Power's demand-side management (DSM) activities and results for 2020 and previews planned activities for 2021. The appendices provide detailed information on the company's DSM activities and detailed financial information for 2020. *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 2020.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and to provide useful and cost-effective demand response programs as determined by the Integrated Resource Plan (IRP) planning process. Idaho Power strives to offer customers valuable programs and information to help them wisely manage their energy use.

The company achieves energy and demand savings objectives in both its Idaho and Oregon service areas through the careful management of current programs, the offering of new cost-effective programs, and through customer outreach and education. Idaho Power has been locally operated since 1916 and serves more than 585,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon.

Figure 2. 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 seasonal contests, the School Cohort, Water and Wastewater Cohorts, and the HER Program all are primarily focused on behavioral energy savings.

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. Idaho Power shapes these savings based on the end use to estimate energy reduction at specific times of the day and year. The company'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 incentives are offered to its irrigation, industrial, large-commercial, small business, government, and school customers to promote a wide range of energy-saving projects.

Energy efficiency and demand response funding comes from Idaho Power base rates, the Idaho and Oregon Energy Efficiency 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 on DSM-related activities from all funding sources were $50.6 million in 2020 (Figure 3).

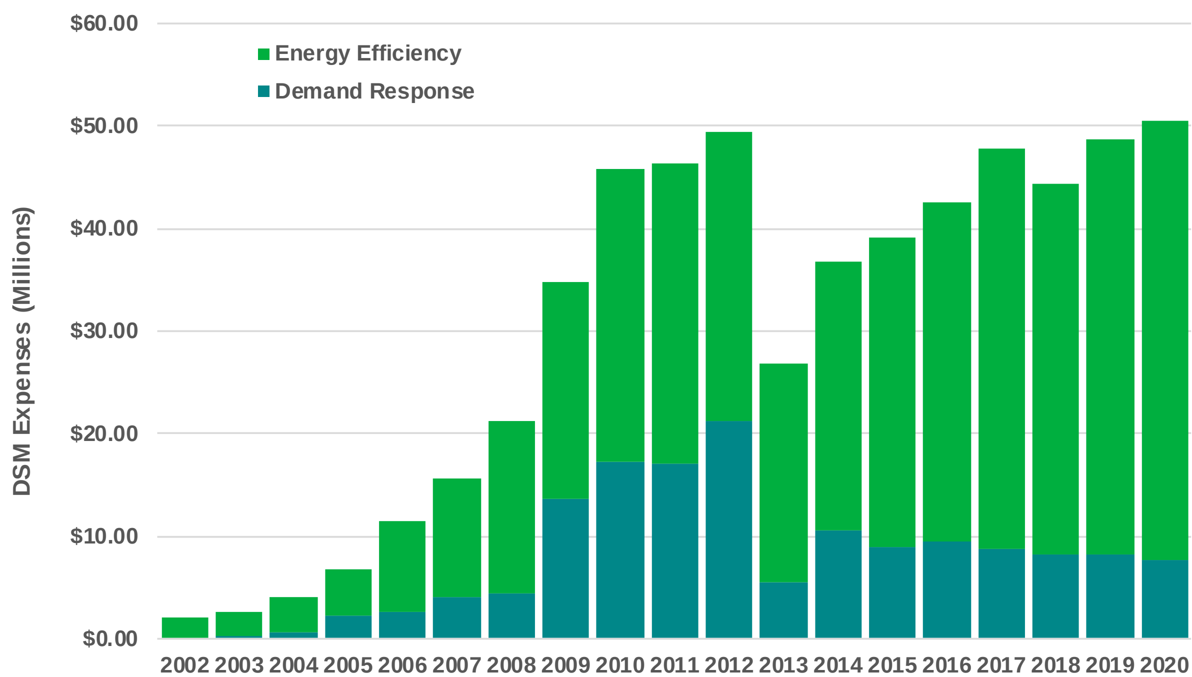

Figure 3. DSM expense history by program type, 2002–2020 (millions [$])

Idaho Power started its modern demand response programs in 2002, and now has over 11% of its all-time peak load available to respond to a peak load event during the summer. 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 predicted system deficits. Demand response program results are measured by the amount of demand reduction, in (MW), achieved by the company during the summer peak time.

DSM Program Performance

Idaho Power's portfolio of energy efficiency program savings remained strong in 2020 with the second highest savings since the Idaho Rider began in 2002. The 2020 total savings of 196,809 MWh including the estimated savings from the Northwest Energy Efficiency Alliance (NEEA), decreased by only 6,493 MWh compared to the 2019 savings of 203,302 MWh—a 3% year-over-year decrease. The 2020 savings represent enough energy to power over 17,000 average homes in Idaho Power's service area for one year. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, were 180,818 MWh in 2020 and 184,934 MWh in 2019—a 2% year-over-year decrease (Figure 4). Idaho Power invests significant resources to maintain and improve its energy efficiency and demand response programs and was able to achieve near record savings even with extensive disruptions to many programs due to COVID-19 protocols.

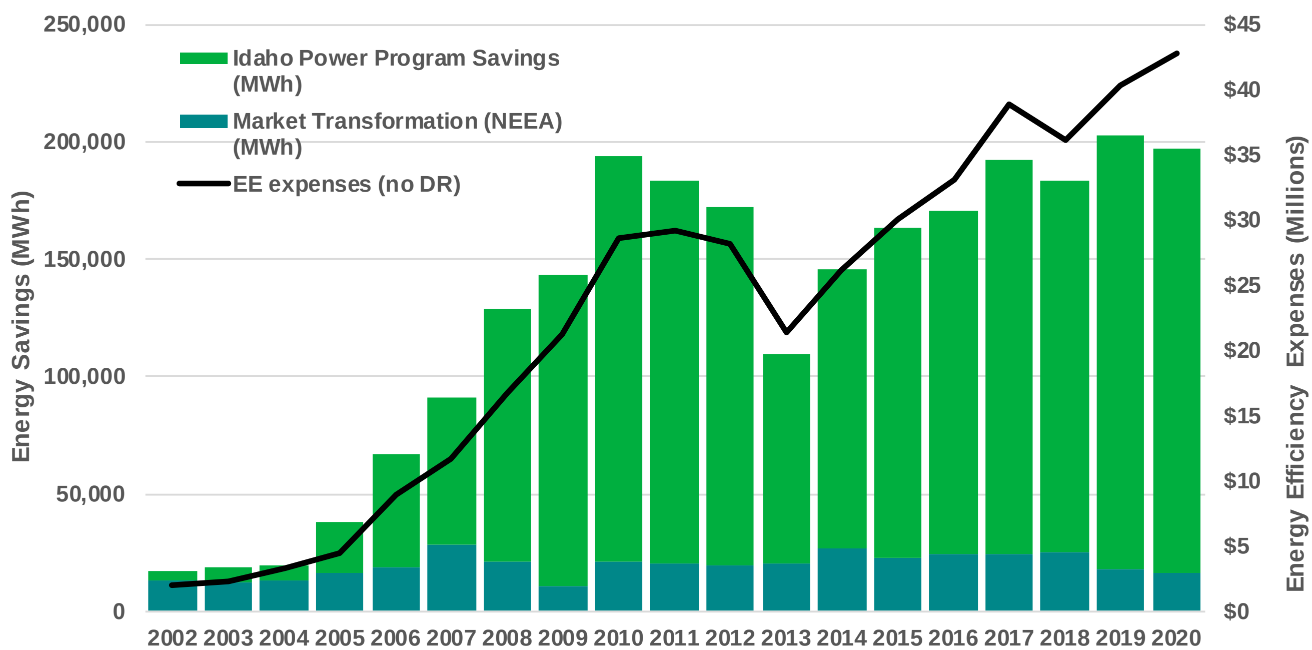

Figure 4. Annual energy savings and energy efficiency program expenses, 2002–2020 (MWh and millions [$])

The 2020 savings results consisted of 37,302 MWh from the residential sector, 130,633 MWh from the commercial/industrial sector, and 12,884 MWh from the irrigation sector. The C&I sector programs contributed 72% of the direct program savings. In the residential sector, lighting continued to significantly contribute to program savings with the Energy Efficient Lighting program contributing 37% of the residential savings and Energy Efficient Lighting combined with Educational Distributions contributing 63% of residential savings. See tables 1 and 2 for a complete list of programs and sector-level savings.

Demand Response

In summer 2020, Idaho Power had a combined maximum actual non-coincidental load reduction from all three programs of 336 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 2020 capacity of demand response programs was 366 MW (Figure 5). The demand response capacity is calculated using the 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 the maximum nominated amount of load reduction. 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.

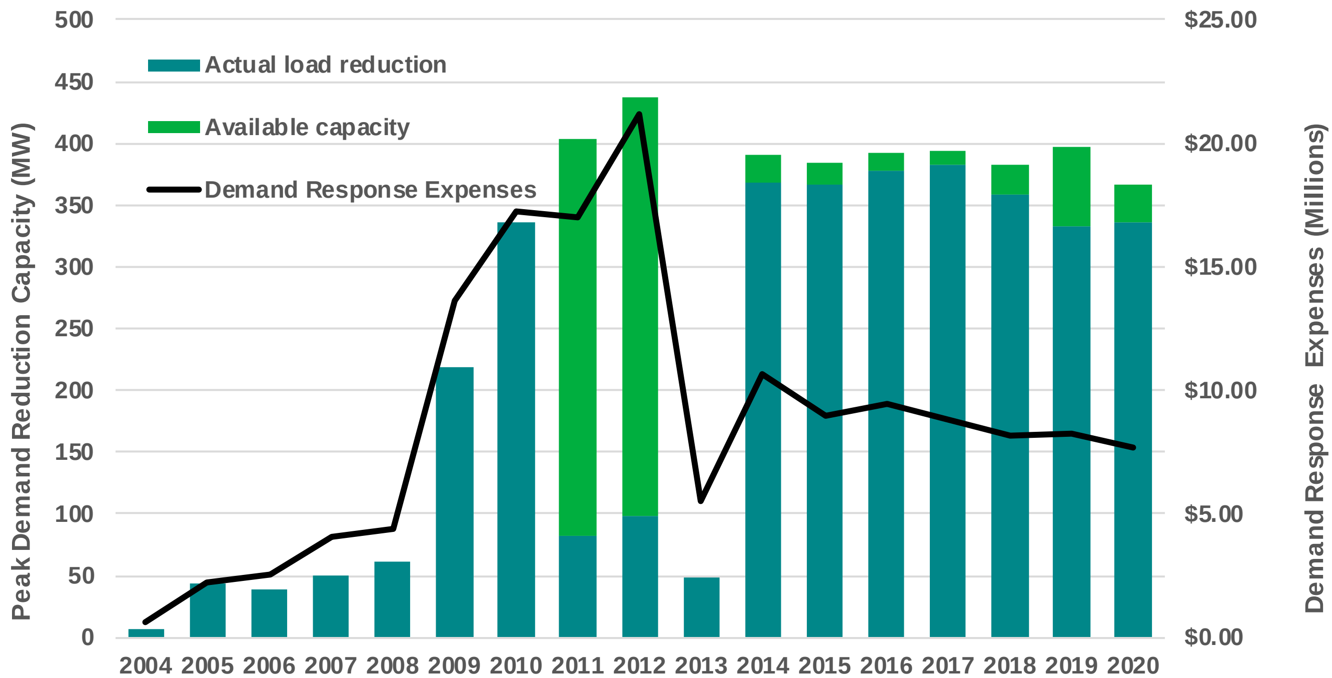

Figure 5. Peak demand-reduction capacity and demand response expenses, 2004–2020 (MW and millions [$])

Under the terms of the Idaho Public Utilities Commission (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. During the IRP process, the company analyzes if and when expanded demand response capacity will be needed to avoid system peak deficiencies.

Energy Efficiency

Table 3. DSM programs by sector, operational type, and location, 2020

Program by Sector	Operational Type	State
Residential		
A/C Cool Credit	Demand Response	ID/OR
Easy Savings: Low-Income Energy Efficiency Education	Energy Efficiency	ID
Educational Distributions	Energy Efficiency	ID/OR
Home Energy Report Program	Energy Efficiency	ID
Energy Efficient Lighting	Energy Efficiency	ID/OR
Energy House Calls	Energy Efficiency	ID/OR
Heating & Cooling Efficiency Program	Energy Efficiency	ID/OR
Home Energy Audit Program	Energy Efficiency	ID
Multifamily Energy Savings Program	Energy Efficiency	ID/OR
Oregon Residential Weatherization	Energy Efficiency	OR
Rebate Advantage	Energy Efficiency	ID/OR
Residential New Construction Pilot Program	Energy Efficiency	ID/OR
Shade Tree Project	Energy Efficiency	ID
Simple Steps, Smart Savings™	Energy Efficiency	ID/OR
Weatherization Assistance for Qualified Customers	Energy Efficiency	ID/OR
Weatherization Solutions for Eligible Customers	Energy Efficiency	ID
Commercial/Industrial		
Commercial and Industrial Energy Efficiency Program		
Custom Projects	Energy Efficiency	ID/OR
Green Motors—Industrial	Energy Efficiency	ID/OR
New Construction	Energy Efficiency	ID/OR
Retrofits	Energy Efficiency	ID/OR
Commercial Energy-Saving Kits	Energy Efficiency	ID/OR
Flex Peak Program	Demand Response	ID/OR
Oregon Commercial Audits	Energy Efficiency	OR
Small Business Direct Install	Energy Efficiency	ID/OR
Irrigation		
Irrigation Efficiency Rewards	Energy Efficiency	ID/OR
Green Motors—Irrigation	Energy Efficiency	ID/OR
Irrigation Peak Rewards	Demand Response	ID/OR
All Sectors		
Northwest Energy Efficiency Alliance	Market Transformation	ID/OR

Table 4. DSM programs by sector summary and energy usage/savings/demand reduction, 2020

	Energy Efficiency Program Impacts [a]			Idaho Power System Sales		
	Program Expenses	Energy Savings (MWh)	Peak-Load Reduction (MW)[b]	Sector Total (MWh)	Percentage of Energy Usage	Year-End Number of Customers
Residential	$ 8,937,132	37,302		5,414,951	37%	491,229
Commercial/Industrial	24,474,163	130,633		7,364,382	50%	74,533
Irrigation	3,401,673	12,884		1,987,418	13%	20,309
Market Transformation	2,789,210	15,991				
Demand Response	7,714,912	n/a	336			
Direct Overhead/ Other Programs	3,239,213	n/a				
Total Direct Program Expenses	**$ 50,556,303**	**196,809**	**336**	**14,786,751**	**100%**	**586,071**

[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% peak line loss assumptions.

Customer Education

Idaho Power produced one *Energy Efficiency Guide* in 2020 and distributed it in April primarily as an insert in 20 local newspapers. Because of COVID-19, Idaho Power increased digital communication efforts to bring a variety of energy and money-saving tips to customers. Idaho Power also distributed 2,424 copies of *30 Simple Things You Can Do to Save Energy* booklet directly to customers. Prior to COVID-19 shutdowns, Idaho Power participated in the Idaho Remodeling and Design Show, Smart Women, Smart Money and the Canyon County winter home show. In 2020, despite the pandemic challenges, Idaho Power's EOEAs delivered over 300 presentations with energy-savings messages to audiences of all ages.

Idaho Power supports the Integrated Design Lab (IDL), which conducted Lunch & Learn sessions to educate architects, engineers, and other design and construction professionals about various energy efficiency topics. In 2020, the IDL scheduled 20 technical virtual technical training sessions and 366 architects, engineers, designers, project managers, and other interested parties attended. Also, IDL hosted six virtual monthly Building Simulation Users Group (BSUG) sessions with 105 professionals attending.

The IDL also maintains an Energy Resource Library (ERL) with tools for measuring and monitoring energy use and provides training on how to use them. The ERL includes over 900 individual pieces of equipment, with 34 new tools added in 2020.

Idaho Power continued to provide training to its commercial and industrial customers in 2020, delivering five total full-time days over the course of 12 days of technical classroom-based, live, online training sessions to 179 unique logins. Due to the virtual nature of the course delivery, in some cases there were multiple attendees at a single login location.

In 2020, Idaho Power provided five irrigation workshops and participated in two additional vendor hosted workshops promoting irrigation system efficiency. The company also participated in and had an exhibit at four agricultural trade shows prior to COVID-19 restrictions, the Idaho Irrigation Equipment Association Winter Show, Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, and the Agri Action Ag Show.

Surveying Customer Satisfaction

Relationship surveys measure the satisfaction of several aspects of a customer's relationship with Idaho Power, including energy efficiency, at a very high level. However, the surveys are not intended to measure all aspects of the energy efficiency programs.

The 2020 results of Idaho Power's customer relationship survey showed near-record overall customer satisfaction. Sixty-six percent of customers indicated their needs were met or exceeded by Idaho Power encouraging energy efficiency among its customers. Figure 6 depicts the percentage of customers who indicated Idaho Power met or exceeded their needs concerning the energy efficiency efforts it encouraged each year since 2010.

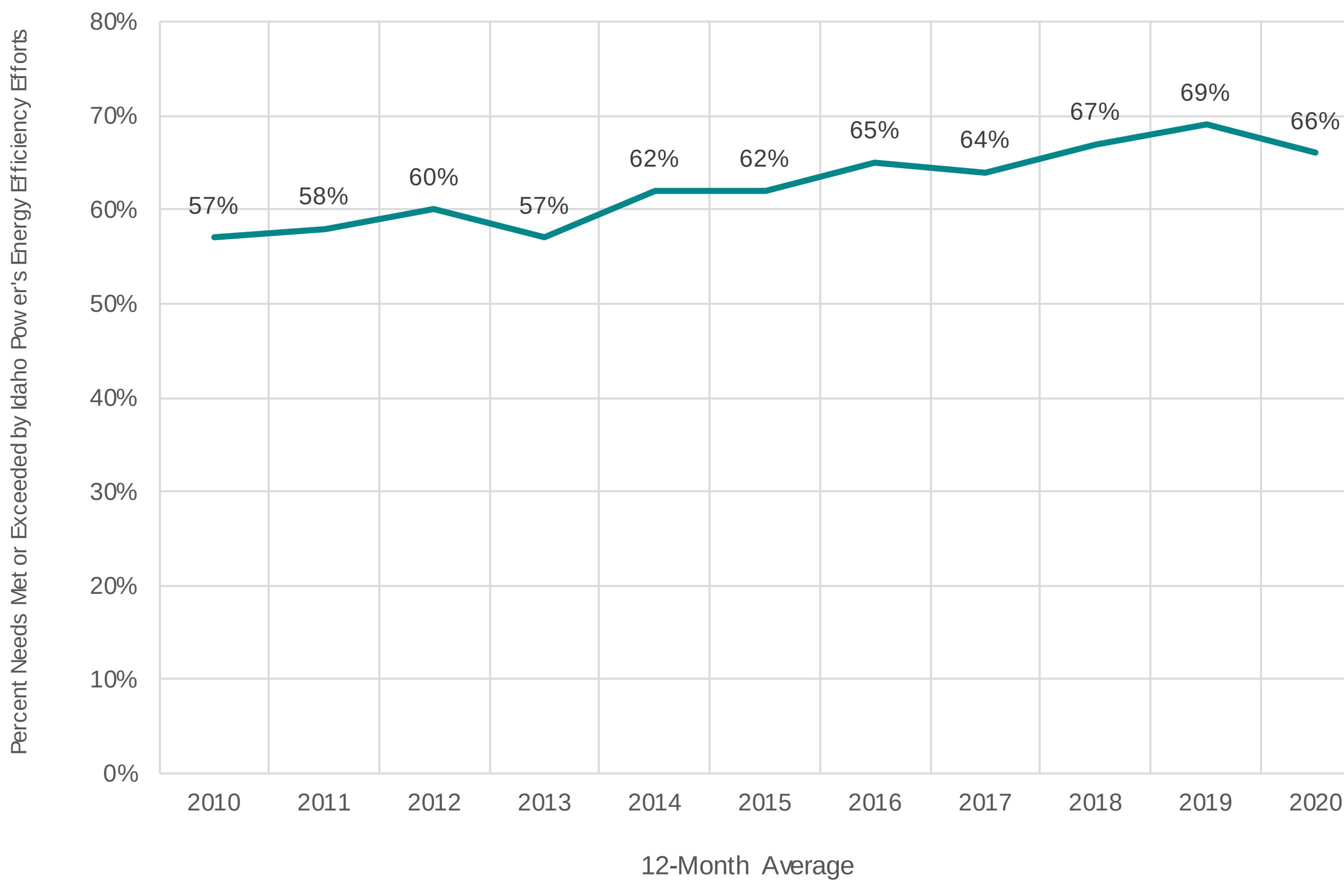

Figure 6. Customers' needs "met" or "exceeded" (%), 2010–2020

The 2020 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 2020, 44% of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program, and 92% were "very" or "somewhat" satisfied with the program they participated in.

Results for the sector-level, program-level, and 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 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 and research to continuously refine its DSM programs.

For a summary of evaluation results, recommendations, and responses, see each program section. For copies of 2020 program evaluation reports and the evaluation schedule, 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. Prior to the actual implementation, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design or measure will be cost-effective. 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 total resource cost (TRC) test, utility cost test (UCT), and participant cost test (PCT) at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test adds value when evaluating program performance. In 2020, Idaho Power began transitioning to using the UCT as the primary cost-effectiveness test for energy efficiency resource planning as directed by the IPUC in Order No. 34503. The company plans to continue to calculate the TRC test and PCT because each perspective can help inform the company and stakeholders about a particular program's or measure's effectiveness. Additionally, programs and measures offered in Oregon must still use the TRC test as the primary cost-effectiveness test as directed by the OPUC in Order No. 94-590

There are many assumptions when calculating the cost-effectiveness of a given program or measure. Savings can vary based on a variety 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 an existing program or measure is shown not to be cost-effective, Idaho Power works with the EEAG to obtain input before making its determination on continuing, discontinuing, or modifying an offering. The company must demonstrate why a non-cost-effective measure or program continues to be offered and communicate the steps the company plans to take to improve cost-effectiveness. 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, 2017, and 2019 (amended) IRPs to be $18.5, $19.8, and $19.6 million, respectively.

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 2020, the cost of operating the three demand response programs was $7.7 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $10.9 million and would have remained cost-effective.

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 individuals representing 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 additional conference calls and/or webinars to address special topics. In 2020, four EEAG meetings and two webinars were held. The meetings were on February 13, May 6, August 5, and November 12 and the webinars were on April 28 and October 8. 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 program evaluations and research.

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 how changes in the IRP will impact DSM alternate costs, which Idaho Power uses in calculating cost-effectiveness. In the meetings, Idaho Power frequently requests input and feedback from EEAG members on several topics, including programmatic changes, marketing tactics, and incentive levels. EEAG often recommends presentation ideas for future meetings.

Throughout 2020, Idaho Power relied on input from EEAG on the following important topics. For complete meeting notes, see *Supplement 2: Evaluation*.

COVID-19 Impacts

The COVID-19 pandemic had broad impacts to the company's energy efficiency efforts. Idaho Power worked diligently to seek new ways to maintain activity while prioritizing the safety of customers, contractors, EEAG members, and employees. After the February quarterly EEAG meeting, the company transitioned to virtual meetings, and worked closely with members to use technology to maintain participation.

Starting with the May 6 EEAG meeting, Idaho Power provided a COVID-19 program status to summarize which programs are or are not affected by COVID-19 protocols. Much of the company's in-home or on-location work was suspended in the early months of the pandemic, but as state safety-guidelines were developed, some work on-location resumed at various businesses. In the early summer, state agencies resumed work for the Idaho and Oregon WAQC programs. The company took the opportunity to transition workshops, trainings, and some Commercial & Industrial inspections to a virtual format. This change helped successfully maintain participation, and EEAG feedback was positive. After consulting EEAG on the market feedback surrounding incentives and opportunities to increase participation when safe to resume activity, Idaho Power increased incentives in the C&I Energy Efficiency program for the professional assistance incentives (PAI) within the New Construction option and lighting incentives in the Retrofits option. This helped drive additional participation in the second half of 2020.

At the meetings, Idaho Power shared how it was using its various marketing channels to help customers understand operational changes due to COVID-19 restrictions. For example, the company quickly added webpage alerts to explain program availability and guided customers to new participation opportunities, including online training, as early as the April *Energy@Work* newsletter.

As the pandemic continued in 2020, the company shared how it updated marketing material to provide energy efficiency tips for customers who may be spending more time at home, and how it successfully marketed virtual training sessions resulting in high trade ally participation.

WAQC and Weatherization Solutions for Eligible Customers

Idaho Power held a webinar October 2020, to review the results of the third-party energy savings billing analysis completed for the Weatherization Assistance for Qualified Customers and Weatherization Solutions for Eligible Customers programs. EEAG members asked questions about the types of homes weatherized, as well as the types of equipment in homes such as heat pumps or air conditioning (A/C) units. After sharing the results of the billing analysis, the company highlighted that future program cost-effectiveness would be impacted by incorporating the new energy savings assumptions. Idaho Power opened the discussion to explore ways to improve program cost-effectiveness and provided three potential ideas, one EEAG member noted that there is potential to explore using measure lists to improve program cost-effectiveness. EEAG members had additional questions on the types of measures installed and the other funding sources for the programs and how they are leveraged. A more in-depth review of the two programs will be delivered to EEAG in the first quarter of 2021, incorporating discussion about a new billing tool which may improve program cost-effectiveness.

Educational Distributions

Idaho Power incorporated new lighting energy savings assumptions from the RTF in evaluation of its three education distribution offerings, Welcome Kits, SEEK, and Energy-Savings Kits, and found that claimed savings had significantly decreased. The company shared the program impacts at the August EEAG meeting and advised that the Welcome Kits would no longer be cost-effective with the new savings assumptions, but Idaho Power was evaluating opportunities to offer the kit in a different format. An EEAG member suggested the company continue to evaluate delivery methods that may keep energy savings high. Because the ESKs would no longer be cost-effective and the offering was reaching market saturation, Idaho Power proposed to sunset the program by year-end 2020 while it was still cost-effective. The company requested EEAG feedback on ideas for the final marketing push suggesting a "last chance" tactic. During the November 2020, EEAG meeting, Idaho Power shared it had run three marketing campaigns for the ESKs and incorporated the last chance messaging. The customer response-rate was positive, with kit distribution of 17,000 since the August update. The company also shared it was posting the number of kits remaining on the order portal in an effort to help drive final participation.

Simple Steps, Smart Savings™

The August EEAG meeting included a discussion on the Energy Efficient Lighting and Simple Steps, Smart Savings™ program which are a subset of the Simple Steps, Smart Savings™ program administered by Bonneville Power Administration (BPA). BPA planned to sunset the regional program on September 30, 2020, resulting in the company discontinuing its retail buy-down programs on the same date. The company explained that it was exploring an alternative program focusing on energy savings related to lighting. EEAG members asked questions about the cost-effectiveness of a local program versus the BPA regional program and one was glad that Idaho Power was pursuing a possible replacement. At the November EEAG meeting, Idaho Power updated members about an Energy Trust of Oregon (ETO) analysis of a lighting retail buy-down offering. ETO found that the LED market is less transformed at certain retailers. While some retailers almost exclusively offer LEDs on their shelves, certain retailers continue to stock a high proportion of less-efficient bulbs, and customers are more likely to purchase these less-efficient bulbs. By continuing the buy-down offering for LEDs at these retailers, ETO found there was more potential to claim energy savings. When the company asked for EEAG feedback on continuing to explore a buy-down option for a portion of the retail market, a member complimented the company and thought this was a smart way to manage this transition.

Future Plans for DSM Programs

Idaho Power will continue to pursue all prudent cost-effective energy efficiency and the amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecasted levels of energy efficiency and demand response are determined by Idaho Power's biennial IRP planning process. 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.

In 2019, the IPUC issued Order No. 34503 directing Idaho Power to use the UCT for energy efficiency resource planning. In 2020, the company contracted with a third party to develop a new energy efficiency potential study, and Idaho Power also updated its third-party Commercial/Industrial Technical Reference Manual (TRM) to take into account the International Energy Conservation Code (IECC) 2018 energy codes expected to be in effect January 1, 2021.

The company continuously searches for new measures for its programs through a membership in E Source, contacts with other utilities, participation in the NEEA Regional Emerging Technology Advisory Committee (RETAC), and from the RTF. Idaho Power representatives also attend national conferences and participate in webinars hosted by organizations interested in advancing energy efficiency savings.

Idaho Power will continue to work in consultation with EEAG to expand or modify its energy efficiency portfolio. Future plans for individual programs are included under each programs' 2020 Program and Marketing Strategies section.

Throughout 2019, Idaho Power monitored the government's activities in relation to the next phase of the Energy Independence and Security Act (EISA) and considered how policy changes would affect the company's Energy Efficient Lighting program and several other predominately residential programs. Signed by President Bush in 2007, EISA called for energy reduction goals "to move the United States toward greater energy independence and security." Title III of the act contained standards for 10 residential appliances and lighting.

The initial 25% greater efficiency goal for general service lightbulbs was phased in between 2012 through 2014. In 2017, the definition of general service was expanded to include A-lamp (pear-shaped bulbs), reflector, candelabra, three-way, and other specialty bulbs. By 2020, all general service lightbulbs were to provide 45 lumens per watt, which is approximately 65% more efficient than the original, pre-EISA incandescent lightbulb. In September 2019, the US Department of Energy (DOE) determined the general service definition did not need to be amended to include bulbs other than the A-lamp and withdrew the 2017 regulation expanding the definition. In December 2019, the DOE's final determination on the EISA 2020 lighting standards eliminated the 45-lumen-per-watt requirement for all residential general service incandescent lightbulbs.

Anticipating the increased standards that were scheduled to go into effect January 1, 2020, Idaho Power considered phasing out its programs that included energy-efficient screw-in bulbs. After the DOE's final determination announcement eliminated this increase in standards, Idaho Power decided to continue these offerings in lighting.

The company uses a third-party vendor in association with BPA for the Energy Efficiency Lighting and Simple Steps, Smart Savings™ programs, which helps the company realize lower administrative costs. BPA's program is called Simple Steps, Smart Savings™ (Simple Steps). Despite the DOE's final determination to eliminate the 45-lumen-per-watt requirement for incandescent lightbulbs, BPA planned to discontinue its Simple Steps program at the end of its 2020 federal fiscal year, September 30, 2020. According to BPA, "…the residential lighting market has transformed; high-efficiency lamps are becoming the norm rather than the exception." Due to reductions, then ultimate removal of claimed energy savings assumptions for high-efficiency showerheads by the RTF, the appliance buy-down portion of BPA's Simple Steps program would also no longer be cost-effective after 2020. Idaho Power committed to offering the Simple Steps program to customers until BPA discontinued its program. In advance of the discontinuation date, the company evaluated opportunities for an alternative program that offers energy-efficient screw-in bulbs.

In 2021, 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 its 2020–2024 funding cycle.

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

DSM Annual Report Structure

The *Demand-Side Management 2020 Annual Report* consists of this main document and two supplements.

The main document contains the following sections related to 2020 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; and 3) four appendices of data related to payments, funding, and program-level costs and savings. Where appropriate, plans for 2021 are also discussed.

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 IDL reports, research and survey reports, evaluation reports, and other reports.

2020 DSM Program Activity

DSM Expenditures

Funding for DSM programs in 2020 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. The 2020 Idaho Rider was 2.75% of base revenues. The 2020 Oregon Rider was 4% of base rate revenues. Additionally, Idaho demand response program incentives were funded 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.

Table 5 shows the total expenditures funded by the Idaho and Oregon riders and Idaho Power base rates resulting in Idaho Power's total DSM expenditures of $50,556,303. The non-rider funding category includes the company's demand response incentives in Idaho, Weatherization Assistance for Qualified Customers (WAQC) expenses, and O&M costs.

Table 5. 2020 funding source and energy savings

Funding Source	Expenses	MWh Savings
Idaho Rider	$40,409,911	190,009
Oregon Rider	1,786,954	6,571
Idaho Power Base Rates	8,359,437	229
Total	**$50,556,303** [a]	**196,809**

[a] Totals may not sum due to rounding.

Table 6 and Figure 7 indicate 2020 DSM program expenditures by category. While the Incentive Expense category illustrates the amount paid directly to customers for their participation in an energy efficiency or demand response program, the other categories include items or services that directly benefited customers. The majority of the expenses in the Materials & Equipment category includes the following items: Energy-Savings Kits (ESK), Welcome Kits, SEEK, Educational Distributions Giveaways, and Commercial Energy-Savings Kits that were distributed to customers ($2,254,279) direct-install weatherization measures ($33,700). The expenses in the Other Expense category include marketing ($1,236,416), Custom Projects energy audits ($221,070), program evaluation ($93,097), and program training ($77,784). The Purchased Services category includes payments made to NEEA ($2,789,210) and third-party contractors who help deliver Idaho Power's programs.

Table 6. 2020 DSM program expenditures by category

Program Expenditure Category	Total	% of Total
Incentive Expense	$31,823,660	63%
Labor/Administrative Expense	3,971,391	8%
Materials & Equipment	2,309,425	5%
Other Expense	1,680,329	3%
Purchased Services	10,771,499	21%
Total	**$50,556,303** [a]	**100%**

[a] Dollars been rounded to the nearest whole unit, which may result in minor rounding differences.

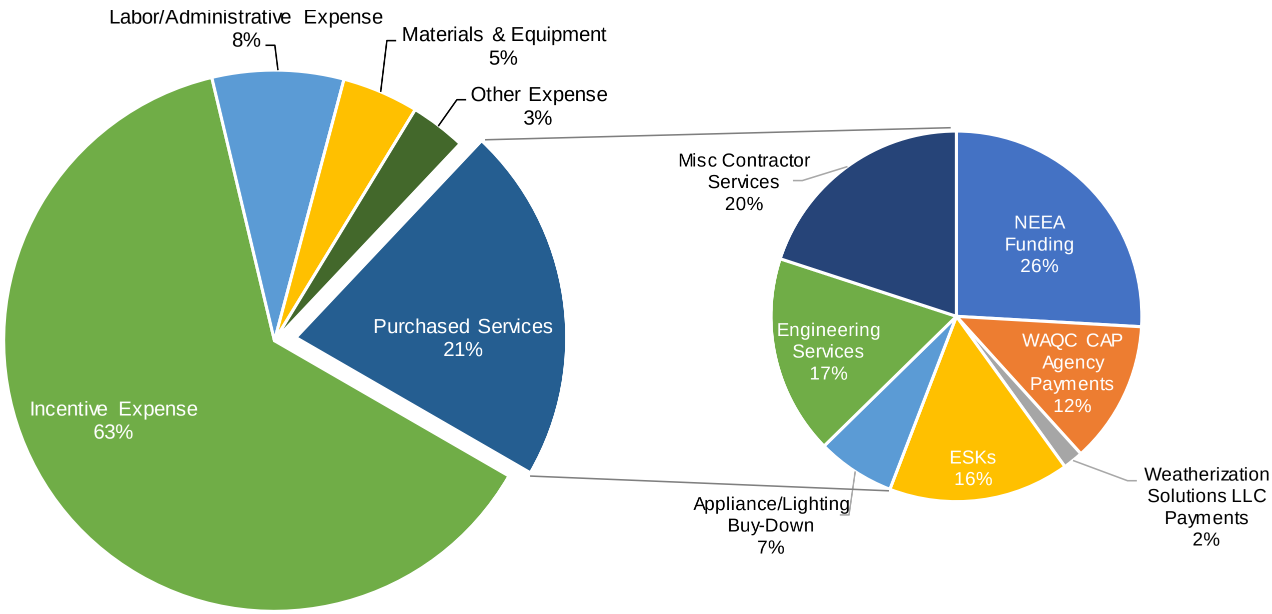

Figure 7. 2020 DSM program expenditures by category

Table 7. 2020 DSM program incentive totals by program type and sector

Program Type—Sector	Total	% of Total
DR[a]—Residential	$336,410	1.1%
DR—Commercial/Industrial	$450,450	1.4%
DR—Irrigation	$6,124,937	19.2%
EE[b]—Residential	$1,765,985	5.5%
EE—Commercial/Industrial	$20,177,062	63.4%
EE—Irrigation	$2,968,817	9.3%
Total	**$31,823,660** [c]	**100.0%**

[a] DR = demand response

[b] EE = energy efficiency

[c] Dollars been rounded to the nearest whole unit, which may result in minor rounding differences.

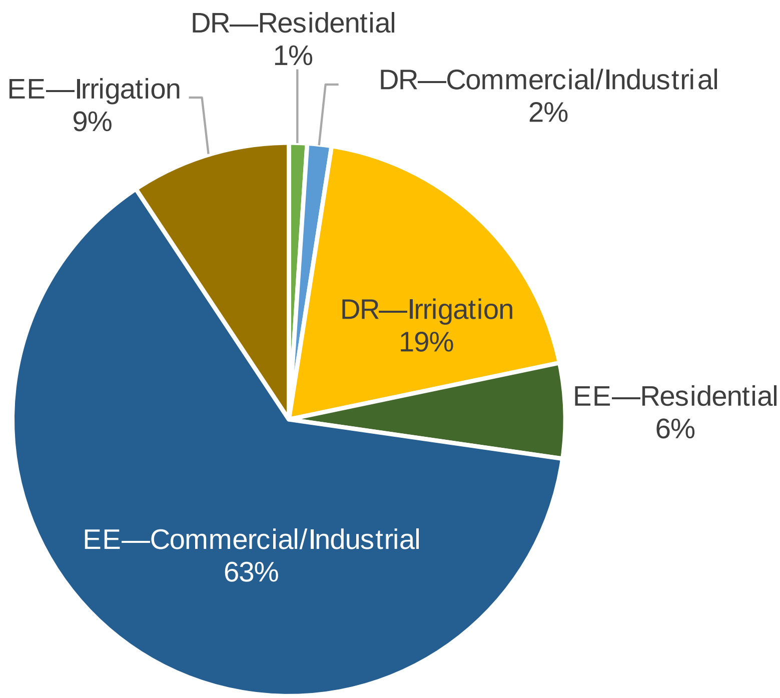

Figure 8. Percent of DSM program incentive expenses by program type and sector, 2020

Marketing

Idaho Power used multi-channel marketing and public relations (PR) strategies in 2020 to improve communication and increase energy efficiency program awareness among its customers. The company uses a wide variety of media and marketing; owned media (social, website, and newsletters) and paid media (advertising and sponsorships), which allow Idaho Power to control the content. Earned unpaid media (news coverage, Idaho Power's *News Briefs* sent to reporters, third-party publications, and television news appearances) gives Idaho Power access to a broader audience through alternative channels that help establish credibility and brand trust. Though the company has less control with earned unpaid media, the value is established through the third-party endorsement.

Idaho Power marketing staff networks with organizations across the region and industry to ensure it is informed about current and future marketing trends and successes. Idaho Power continued to work with NEEA to coordinate, collaborate, and facilitate marketing for all sectors. To build marketing networks and to learn what works in other regions, Idaho Power staff virtually attended a variety of conferences and webinars throughout the year, such as the E Source Utility Marketing Executive Council and Forum in September.

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

Social Media

Approximately 18% of the company's total social media content promoted energy efficiency in 2020. Idaho Power regularly posted messages encouraging energy efficiency behaviors, program enrollment, and customer engagement on Facebook, Twitter, YouTube, and LinkedIn. Because of the need to use social media for COVID-19 related customer communication, the percentage of content related to energy efficiency dipped slightly from previous years. Social media content also showcased local businesses and organizations that have benefitted from Idaho Power energy efficiency efforts. Idaho Power engaged with customers that posted their own social media content about Idaho Power programs, such as Energy-Saving Kits. Idaho Power's Facebook page hosted two customer sweepstakes giveaways encouraging customers to enter by leaving a comment about how they save energy in the summer or fall.

In 2020, Idaho Power social channels focused on sharing energy efficiency tips that made sense for customers spending more time at home. Graphics were updated to be more engaging and representative of behavior changes customers could make without spending any money or leaving the house. Tips were also provided to help businesses save energy while operating with fewer employees or with reduced working hours. When timely and appropriate, past *#TipTuesday* content was repurposed and shared, as well.

Idaho Power's Facebook followers increased 8.6% in 2020, from 20,982 at the end of 2019 to 22,800 at the end of 2020. Facebook remains the company's priority channel for engaging directly with customers and was the main platform in 2020 for focusing on COVID-19 safety messages, energy assistance for customers, crisis communications, energy efficiency tips and program offerings, and helping customers with account-related issues through private messages.

Idaho Power uses Twitter to communicate about media items, large outages, company news, and energy efficiency. COVID-19 messaging was also shared on the platform in 2020. Idaho Power's Twitter followers increased 3.5% in 2020, from 6,000 followers to 6,210.

Idaho Power again saw a favorable increase in followers on LinkedIn with 1,992 new followers in 2020. LinkedIn is an effective channel for engaging business and commercial customers in energy efficiency, as well as positioning the company as a good corporate citizen, clean energy leader, and employer of choice.

Website

Idaho Power tracked the number of page views to the main energy efficiency pages—also known as landing pages—from external users on the company's website. In 2020, the company's energy efficiency homepage received 6,542 page views, the residential landing page received 192,307 views, and the business and irrigation landing pages received 12,288. 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.

Public Relations

Idaho Power's PR staff supported energy efficiency programs and activities through these channels: videos telling energy efficiency success stories; *Connections*, a monthly customer newsletter distributed in 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 two markets (KTVB in Boise and KMVT in Twin Falls); energy efficiency radio segments; news releases; and public events (such as incentive check presentations).

In 2020, the January and July issues of *Connections* were devoted to energy efficiency. The January issue included a variety of ideas for energy-saving resolutions, such as how to save energy with a pressure cooker, and information about the heat pump water heater (HPWH) incentive. The July edition highlighted, how to save energy during the summer months, how to learn more about energy efficiency with fun at-home activities, and the energy efficiency success story of the Idaho Humane Society.

Idaho Power produced new energy efficiency success story videos in 2020 highlighting the energy efficiency efforts of Sun Valley Resort and the Idaho Humane Society. Combined, the videos received 782 views on YouTube and an additional 5,717 views on Facebook.

The energy efficiency television segments that aired on stations in Boise and Twin Falls continued to receive positive feedback but were limited in 2020 due to COVID-19 restricting guests at television stations. Topics included smart thermostats, energy-efficient kitchen tips, and ways to beat the summer heat. Idaho Power also did a segment on two Pocatello area radio stations about energy efficient holiday cooking.

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 and summer savings tips, phantom load, and the smart thermostat incentive.

2021 Marketing Activities

In 2021, 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 channels. Idaho Power will update the look and messaging of the company's advertising at the Boise Airport. Additionally, the company will continue to update collateral and displays as needed for irrigation programs and various sector trade shows (many of which will be virtual). See the sector overview sections for more specific marketing plans for the future.

Cost-Effectiveness Results

Table 8. Cost-effectiveness summary by energy efficiency program

Program/Sector	UCT	TRC	Ratepayer Impact Measure (RIM)	PCT
Educational Distributions	1.45	2.19	0.45	N/A
Energy Efficient Lighting	4.56	4.20	0.54	7.77
Energy House Calls	0.63	0.77	0.29	N/A
Heating & Cooling Efficiency Program	1.66	0.81	0.45	1.46
Multifamily Energy Savings Program	0.14	0.28	0.11	N/A
Rebate Advantage	1.69	0.98	0.39	2.17
Residential New Construction Pilot Program	1.54	1.20	0.45	2.26
Shade Tree Project*	N/A	N/A	N/A	N/A
Simple Steps, Smart Savings™	0.78	3.24	0.36	13.23
Weatherization Assistance for Qualified Customers	0.20	0.33	0.14	N/A
Weatherization Solutions for Eligible Customers	0.13	0.23	0.10	N/A
Residential Energy Efficiency Sector	**1.64**	**1.91**	**0.45**	**6.41**
Commercial and Industrial Energy Efficiency Program				
Custom Projects	3.26	1.61	1.06	1.42
New Construction	3.40	2.63	0.80	3.14
Retrofits	3.25	1.35	0.79	1.56
Commercial Energy-Saving Kits	1.24	2.38	0.56	N/A
Small Business Direct Install	1.04	1.61	0.53	N/A
Commercial/Industrial Energy Efficiency Sector **	**3.18**	**1.62**	**0.97**	**1.58**
Irrigation Efficiency Rewards	4.00	4.09	1.18	3.96

Program/Sector	UCT	TRC	Ratepayer Impact Measure (RIM)	PCT
Irrigation Energy Efficiency Sector * **	**4.01**	**4.09**	**1.18**	**3.96**
Energy Efficiency Portfolio	**2.71**	**2.08**	**0.83**	**2.45**

* Shade Tree Project tree distributions were suspended in 2020 due to COVID-19, no newly planted trees in 2020 to report energy savings.
** 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 concerns about 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 programs have been changed significantly. Throughout 2020, 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 online panel—Empowered Community. Results of these studies are included in *Supplement 2: Evaluation*.

The sector-level results of the *2020 Burke Customer Relationship Survey* are available in the Residential, Commercial and Industrial, and Irrigation sector overview sections of this report.

Evaluations

In 2020, Idaho Power contracted with ADM Associates, DNV GL and Tetra Tech to conduct program evaluations for the Educational Distributions (impact and process, DNV GL), the HER Program (process, DNV GL), Irrigation Efficiency Rewards (impact and process, Tetra Tech), and Rebate Advantage (impact, ADM Associates) programs. Nexant conducted a joint billing analysis for the WAQC and Weatherization Solutions for Eligible Customers programs. Idaho Power also contracted Tetra Tech to conduct a process evaluation on the Small Business Direct Install (SBDI) program. The start of the evaluation has been delayed until the second quarter of 2021 to allow time for more installs to be completed after on-site program activity was suspended in early 2020 due to the COVID-19 pandemic. DNV GL started the HER process evaluation alongside the Educational Distributions evaluation. However, due to some late findings, additional analysis was required to complete the evaluation. The HER evaluation will be completed in April 2021 and will be included in the 2021 annual report.

Franklin Energy conducted a program summary analysis for residential ESKs as well as SEEK. Aclara conducted a savings analysis for the HER Program. AM Conservation conducted a program summary analysis for Commercial Energy-Savings Kits. Idaho Power conducted internal analyses of the 2020 demand response events for Irrigation Peak Rewards, Flex Peak, and A/C Cool Credit programs.

A summary of each of these evaluations is available in the respective program sections. An evaluation schedule and the final reports from evaluations and research completed in 2020 are provided in *Supplement 2: Evaluation*.

Residential Sector Overview

In 2020, Idaho Power's Residential sector consisted of 484,433 customers averaged throughout the year; Idaho customers numbered 470,804 and eastern Oregon had 13,629. In 2020, the number of Residential sector customers increased by 13,135, an increase of 2.8% from 2019. The Residential sector represented 36.7% of Idaho Power's actual total electricity usage and 46.3% of overall revenue in 2020.

Table 9 shows a summary of 2020 participants, costs, and savings from the residential energy efficiency programs.

Table 9. Residential sector program summary, 2020

			Total Cost		Savings	
Program	**Participants**		**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response						
A/C Cool Credit	22,536	homes	$ 765,020	$ 765,020		19
Total			**$ 765,020**	**$ 765,020**		**19**
Energy Efficiency						
Easy Savings: Low-Income Energy Efficiency Education	155	HVAC tune-ups	$ 9,503	$ 9,503	10,628	
Educational Distributions	97,228	kits/giveaways	3,106,820	3,106,820	9,481,801	
Energy Efficient Lighting	1,148,061	lightbulbs	1,667,159	3,065,781	13,942,202	
Energy House Calls	51	homes	46,352	46,352	56,944	
Heating & Cooling Efficiency Program	1,019	projects	606,559	1,911,792	1,839,068	
Home Energy Audit	97	audits	130,546	142,649	31,938	
Home Energy Report Program	127,138	treatment size	899,203	899,203	10,427,940	
Multifamily Energy Savings Program	33	units	89,829	89,829	28,041	
Oregon Residential Weatherization	0	audits/projects	5,313	5,313	0	
Rebate Advantage	116	homes	180,422	437,263	366,678	
Residential New Construction Pilot Program	248	homes	473,504	865,989	649,522	
Shade Tree Project*	0	trees	28,490	28,490	52,662	
Simple Steps, Smart Savings™	6,894	appliances/ showerheads	99,141	98,629	148,404	
Weatherization Assistance for Qualified Customers	115	homes/non-profits	1,385,577	1,728,293	218,611	
Weatherization Solutions for Eligible Customers	27	homes	208,715	208,715	47,360	
Total			**$ 8,937,132**	**$12,644,620**	**37,301,800**	

Notes:

*Shade Tree Project tree distributions were suspended in 2020 due to COVID-19, no newly planted trees in 2020 to report energy savings; listed savings are from prior-year trees increasing in size.

See Appendix 3 for notes on methodology and column definitions.

Totals may not add up due to rounding.

Energy Efficiency Programs

Easy Savings: Low-Income Energy Efficiency Education

A program offering coupons to income-qualified customers for HVAC tune-ups and one-on-one energy savings education.

Educational Distributions

A multifaceted approach to educating residential customers about their energy consumption: giving away various efficient products, engaging elementary students with in-class and at-home activities, and providing *Home Energy Reports* to help customers understand their energy use.

Energy Efficient Lighting

A BPA-sponsored program to buy down the cost of energy-efficient lighting products. Though discontinued in 2020 by BPA, Idaho Power is researching ways to offer lighting incentives to a wider range of customers.

Energy House Calls

A program designed specifically for manufactured homeowners to test and seal ducting and to offer energy-efficient products designed to reduce energy costs.

Heating and Cooling Efficiency Program

Providing incentives to customers and builders who upgrade existing homes or build new ones using energy efficient heating and cooling equipment and services.

Home Energy Audit

Similar to Energy House Calls, Idaho customers living in multi-family homes with discrete meters or in single-family homes pay a reduced price for an energy audit to identify areas of concern. Participants may also receive energy-efficient products for no additional cost.

Multifamily Energy Savings Program

A program offering renters in multi-family buildings energy-efficient products designed to reduce energy use and power costs.

Oregon Residential Weatherization

No-cost energy audits for Oregon customers who heat with electricity.

Rebate Advantage

Financial incentives for customers who buy energy-efficient manufactured homes and the people who sell them.

Residential New Construction Program

Idaho Power offers builders a cash incentive to construct energy-efficient, above code, single-family, all-electric homes that use heat pump technology for its Idaho customers.

Shade Tree Project

A tree giveaway program for Idaho customers. To maximize summer energy savings, Idaho Power provides participants with a variety of resources to encourage successful tree growth.

Simple Steps Smart Savings™

Like Energy Efficient Lighting, this BPA-sponsored program was discontinued in 2020. Idaho Power is researching ways to provide a replacement program to encourage customers to purchase qualified energy-efficient appliances.

Weatherization Assistance for Qualified Customers and Weatherization Solutions for Eligible Customers

Energy-efficient products, services, and education for customers who meet income requirements and heat with electricity.

Demand Response Program

A/C Cool Credit

A program that gives residential customers a credit for allowing Idaho Power to cycle their A/C units during high-energy demand in the summer.

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. The campaign used radio, television, newspaper advertisements (ads), digital ads, and Facebook ads and boosted posts aimed at a variety of customer demographics across the service area. New in 2020, the company added Spanish network television ads and two seasonally relevant contests: Backyard BBQ Summer Giveaway and Crisp and Cozy Fall Giveaway.

Described below are Idaho Power's 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

Idaho Power continued its effort with email communication in 2020. The company emails only those customers who have supplied their addresses for other business purposes (signing up for paperless billing, for example). Energy efficiency promotional emails included heating and cooling tips, summer and winter contest promotion, and various program promotions (detailed information can be found in respective program sections).

Digital

During the Spring campaign, web users were exposed to 1,834,342 display ads (image ads embedded on 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 the ads 3,864 times, resulting in a click-through rate of 0.21%. In the fall, the display ads received 3,287,312 impressions and 1,645 clicks, resulting in a click-through rate of 0.05%.

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 2,512,351 impressions and 169,836 clicks throughout the year.

Television

Idaho Power used network television, Hulu, and YouTube advertising for the spring and fall campaign. The company also used over-the-top (OTT) media. OTT is a type of streaming media that delivers content to customers watching a certain online show. Most OTT providers have their own app or website and are streamed through devices like Rokus or Amazon Fire TVs. 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 1,609 times in the Boise, Pocatello, and Twin Falls media markets on network television. The ad reached 68% of the Boise target audience (which also reached Malheur County in Oregon), 66% of the Twin Falls target audience, and 44% of the Pocatello target audience. The targeted customers saw the ad 7.1 times in Boise, 9.5 times in Twin Falls, and 6.7 times in Pocatello. Hulu ads delivered 622,036 completions, meaning the ad was viewed in its entirety. OTT ads delivered 430,297 impressions with a 95.5% video completion rate. New in the 2020 Spring Campaign was the addition of Spanish network television ads. The Boise target audience saw 124 paid spots and the Pocatello market saw 51 spots. Spanish TV ads ran during the Fall Campaign as well; the Boise target audience saw 210 paid spots and the Pocatello audience saw 98 spots. Ad reach and frequency information is not available for Spanish stations.

During the fall campaign, the TV spot ran 1,551 times in the Boise, Pocatello, and Twin Falls media markets. The ads reached 79.9% of the Boise target audience, 99.4% of the Twin Falls target audience, and 36.6% of the Pocatello target audience. The targeted customers saw the ad 8.2 times in Boise, 9.7 times in Twin Falls, and 5.2 times in Pocatello. Hulu ads received 577,916 completions, and YouTube video ads delivered 1,567,032 impressions and 4,496 clicks. OTT ads delivered 416,118 impressions with a 97.4% video completion rate.

Idaho Power also sponsored commercials on Idaho Public Television in Boise, Pocatello, and Twin Falls markets that ran a total of 192 times.

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 optimal 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 2,493 English radio spots. These spots reached 72.7% of the target audience in Boise, 57.6% in Pocatello, and 84.8% in Twin Falls. The target audience in Boise was exposed to the ad 6 times, 7.5 times in Pocatello, and 10.9 times in Twin Falls. During the fall campaign, the company ran 4,799 English radio spots. These spots reached 81.6% of the target audience in Boise, 64.5% of the target audience in Pocatello, and 77.1% of the target audience in Twin Falls. The target audience was exposed to the message 10.2 times in Boise, 8 times in Pocatello, and 9.6 times in Twin Falls during the fall campaign.

In spring, Idaho Power also ran 384 ads on Spanish-speaking radio stations and 308 National Public Radio (NPR) ads in the service area targeting adults age 25 to 54. The fall campaign included 369 Spanish ads and 270 NPR ads.

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 452,008 impressions and 215 clicks to the Idaho Power residential energy efficiency web page. The fall ads yielded 451,813 impressions and 175 clicks.

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, *Territory Magazine*, *Idaho Magazine*, Broadway in Boise program, *Boise and Meridian Lifestyle*

Magazine, *IdaHome Magazine*, *Mirada Magazine* (Spanish), and *Sun Valley Magazine*. As part of the print campaign, digital “homepage takeover” ads were featured on KTVB.com, idahopress.com and idahostatesman.com. Homepage takeover ads fill a homepage with ads from one company for a specific timeframe. The spring ads highlighted individual energy efficiency program options and tips, such as adjusting your thermostat and the benefits of planting a shade tree.

In 2020, Idaho Power updated the program information in a spiral-bound guide outlining each of the residential energy efficiency programs, tips, and resources. The updated guide will be included in the 2021 Welcome Kits. The previous edition of the guide was included in 2020 Welcome Kits, provided to Weatherization Assistance customers, and shared with customers who attended events Idaho Power participated in prior to the COVID-19 restrictions.

Social Media

Idaho Power’s Facebook ads received 215,224 total impressions, 8,420 engagements, and 598 link clicks during the spring energy efficiency campaign. During the fall campaign, Facebook ads and boosts received 150,500 total impressions, 6,566 engagements, and 5,900 link clicks. Idaho Power tried two different ad placement tactics in 2020. In the spring, four ads were placed individually: one every two weeks. The fall campaign allowed Facebook to automatically alternate between four different ads over a two-month period. Facebook gave higher priority to the ads that performed better with the targeted audience. This tactic resulted in many more link clicks than in the spring, but fewer total impressions and engagements. Because link clicks represent conversions, this technique is more effective at driving customers to our website than previous techniques and will be used again in 2021.

Throughout the year, Idaho Power used Facebook and Twitter posts and boosted Facebook posts for various programs.

Out-of-Home

In 2020, Idaho Power participated in several new tactics referred to as out-of-home advertising. Out-of-home advertising attempts to reach customers when they are outside of their homes. The tactics were a way to continually maintain energy efficiency program awareness through the year. Tactics included full-side bus wraps on three ValleyRide buses in the Treasure Valley Area that yielded 11,076,912 impressions. Impressions during the year most likely varied due to more customers working from home during COVID-19 restrictions. A quarter wrap also ran on one Pocatello Regional Transit bus in the Eastern Region. A billboard was used in the Homedale area from March through December, which was viewable by 6,900 vehicles per day. The company participated in an Idaho Steelheads sponsorship at CenturyLink Arena in Boise January through March where 91,412 attendees watched a variety of programs, including 16 Steelheads hockey games.

The company sponsored a 4- by 8-foot sign July through December promoting energy efficiency in the College of Southern Idaho (CSI) gym that has a capacity of 2,300. CSI held various events in the gym throughout the year including sporting events, dance competitions, etc. Undoubtedly the sign saw fewer impressions because of COVID-19 restrictions but it is still a very cost-effective tactic to reach customers in the Twin Falls area.

Public Relations

Many of the company’s PR activities focused on the residential sector. Energy-saving tips videos, TV and radio segments, news releases, 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 Crisp and Cozy Fall Giveaway in *News Briefs*.

See the Program Activity section and the Commercial and Industrial Sector Overview for more 2020 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 over 2,100 actively engaged members from across Idaho Power's service area. Idaho Power typically sends one survey per month to active members but in 2020, fewer surveys were conducted out of respect to members and issues associated with COVID-19. In 2020, Idaho Power included seven energy efficiency messages with survey invitations to members resulting in almost 12,400 touchpoints.

Recruitment for the Empowered Community is conducted on an annual basis to refresh the membership each year. Throughout February and March 2020, various types of recruitment were conducted with residential customers including bill inserts, messages on paperless billing emails, pop-up ads on My Account, direct emails, and social media posts. In 2020, 595 new members were added to Empowered Community.

Seasonal Sweepstakes

In 2020, Idaho Power ran two seasonally focused energy efficiency sweepstakes—the Backyard BBQ Summer Giveaway in August and the Crisp and Cozy Fall Giveaway in November.

Both sweepstakes aimed to maintain awareness about energy efficiency and the impact a small change can make.

The summer sweepstakes ran July 24 through August 2 and received 7,316 entries. Customers were asked to comment—through social media or on the Idaho Power website—with a way they saved energy during the hot summer months. In return, participants were entered to win a package of energy-efficient goodies for the backyard. The sweepstakes was promoted with email messaging to 184,146 customers, and social media posts reached 2,363 customers, receiving 617 post engagements (likes, comments, shares). The sweepstakes was also promoted on idahopower.com, through a pop-up ad on the My Account homepage.

The fall sweepstakes ran November 13-22 and received 7,190 entries. Customers were asked to comment—through social media or on the Idaho Power website—with a way they saved energy during the cold months. In return, participants were entered to win one of five toaster oven/air fryer combo units. The sweepstakes was promoted with email messaging to 210,592 customers, and paid social media posts reached 38,566 customers, receiving 2,879 post engagements. The sweepstakes was also promoted through a pop-up ad in the company's My Account homepage. It was featured in a *News Briefs* to media outlets and was promoted on idahopower.com.

Customer Satisfaction

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2020, 61% of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-three percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Fifty-two percent of Idaho Power residential customers surveyed indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 41% 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, 89% are “very” or “somewhat” satisfied with the program.

Based on surveys conducted in 2020, Idaho Power ranked second out of 16 utilities included in the west region midsize segment of the *J.D. Power and Associates 2020 Electric Utility Residential Customer Satisfaction Study*. Sixty-nine 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. Idaho Power customer awareness of energy efficiency programs is among the highest in the nation.

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

Field Staff Activities

Idaho Power’s residential and commercial energy advisors and EOEAs started 2020 with in-person meetings and events to promote energy efficiency programs and offerings with customers. When COVID-19 restrictions were implemented in mid-March, company staff pivoted away from these face-to-face interactions. Idaho Power’s attendance at large, legacy community events such as home and garden shows, remodeling shows, science, technology, engineering, and mathematics (STEM) nights, science fairs, back to school nights, etc., was not an option, as many of these events were postponed or canceled.

Instead, energy advisors used phone, email, mail, text and virtual presentations to stay connected with customers. The energy advisors conducted a callout campaign to residential customers to promote ESKs and created giveaway bags for senior centers that included energy-efficient measures and gifts: a LED lamp, nightlight, energy efficiency information, puzzles, and games. Energy advisors delivered these items while social distancing and wearing masks to keep everyone safe.

Though much of 2020 was spent developing alternative methods for customer interaction, the changes also allowed the company to offer more training and development sessions for energy advisors to expand their knowledge, skills, and abilities about energy efficiency programs, measures, and technologies. Topics included: lighting, building envelope, HVAC, and refrigeration.

A/C Cool Credit

		2020	2019
Participation and Savings			
	Participants (homes)	22,536	23,802
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	19	24
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$405,402	$495,703
	Oregon Energy Efficiency Rider	$25,200	$30,762
	Idaho Power Funds	$334,418	$351,200
	Total Program Costs—All Sources	$765,020	$877,665
Program Levelized Costs			
	Utility Levelized Cost ($/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 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) using the same system utilized by Idaho Power's automated metering system (AMI). 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 the A/C unit will be turned off by the switch. For instance, with a 50% cycling rate, the switch will cycle the A/C unit off for about 30 (nonconsecutive) minutes of each hour. Idaho Power tracks the communication levels to validate whether the signal reaches the switches. Switch communication may be interrupted for a variety of reasons: 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.

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

At the end of the season, Idaho Power or a third-party evaluates the events to determine peak demand savings.

Program Activities

In 2020, about 22,500 customers participated in the program, with approximately 262 in Oregon, and 22,274 Idaho. Three cycling events occurred, and all were successfully deployed (Table 10). The cycling rate was 50% and the communication level exceeded 90% for each event. With a greater number of residents being at home due to the COVID-19 pandemic, the company wanted to minimize the impact of A/C cycling and to mitigate the potential for participation dropouts, so the cycling percentage was reduced from the typical 55% to 50%. The incentive remained $15 per season, paid as a $5 bill credit on the July, August, and September bills.

Table 10. A/C Cool Credit demand response event details

Event Details	Thursday, July 16	Thursday, July 30	Wednesday, August 5
Event time	4–7 p.m.	4–7 p.m.	4–7 p.m.
Average temperature	93°F	103°F	98°F
Maximum load reduction (MW)	15.57	19.39	12.38

Throughout 2020, Idaho Power continued site visits to check switches and equipment to improve communication levels. However, due to COVID-19 restrictions, the company temporarily suspended site visits in March 2020. In mid-May, visits resumed with these restrictions: limiting site visits to the Treasure Valley area, calling each customer before the visit to explain process and safety measures, and not visiting any site where the customer was uncomfortable with the process. While at the site, contractors wore masks, maintained a 6 ft social distance from customers, and performed enhanced disinfecting activities. Due to these protocols to ensure safety as a result of COVID-19, not all device checks were completed. The company will continue work to ensure devices participating in the program are communicating on an ongoing basis.

Idaho Power printed new informational stickers that were placed on devices during site visits. The sticker provides a safety warning and toll-free number customers can call with questions.

Marketing Activities

Per the settlement agreement reached in Idaho Case No. IPC-E-13-14 and Oregon Case UM 1653, Idaho Power did not actively market the A/C Cool Credit program in 2020.

Before the cycling season began, Idaho Power sent current participants a postcard to remind 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. Participating customers received a thank you and a credit reminder message on their summer bills. 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 Idaho Power's demand response programs were cost-effective for 2020.

The A/C Cool Credit program was dispatched for three events (totaling nine event hours) and achieved a maximum demand reduction of 19.4 MW. The total expense for 2020 was $765,020 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

In 2020, Idaho Power performed an internal review to evaluate the demand reduction over the course of the three event days. The demand reduction was calculated by comparing the actual average load for participating customers on each of the three event days to the corresponding baseline. The baseline is estimated by averaging the three non-event weekdays with the highest usage, out of the 10 non-event weekdays prior to an event. The baseline is then adjusted to match the event day in the hour before the start of the event.

The second event on July 30 achieved the highest peak demand reduction of 0.86 kW per participant for a total peak reduction of 19.4 MW with line losses.

For 2020, the maximum potential capacity of the program was calculated to be 31.4 MW. This is based on 1.4 kW per participant which the company has achieved in the past with 65% cycling on a very hot day.

The complete report is available in *Supplement 2: Evaluation*.

2021 Program and Marketing Strategies

Idaho Power does not anticipate any program changes in 2021, though it will conduct site visits with the restrictions detailed above, as necessary.

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. The company will continue 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

		2020	2019
Participation and Savings			
	Participants (coupons)	155	430
	Energy Savings (kWh)	10,628	45,150
	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	$9,503	$145,494
	Total Program Costs—All Sources*	$9,503	$145,494
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.299	$0.885
	Total Resource Levelized Cost ($/kWh)	$0.299	$0.885
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

* Total Program Costs are by calendar year; allotments provided to CAP agencies the beginning of LIHEAP's fiscal year each October. Program and monetary allotment moving to a calendar year in 2021.

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 its 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 ESKs 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 electric HVAC tune-up and one-on-one education with the goal of helping low income customers learn ways to reduce their energy costs and have a maintained HVAC system.

To provide services for the program, regional HVAC company owners sign contractor guidelines and acknowledge the two-fold goal of the program—customer education and equipment tune-up. During the customer visit, HVAC contractors perform the tune-up and teach residents how to change furnace filters. They also explain how regular maintenance improves overall performance and answer questions about the specific heating equipment and ways to save energy. The contractor leaves behind a customer satisfaction survey that can be mailed to CAPAI or completed online. Respondents are entered into a drawing for a gift card.

Program Activities

Coupons were redeemed by customers for electric heating system tune-ups, with all coupon redemptions occurring by end of calendar 2019. Of the $125,000 Idaho Power allotted to CAP agencies for this program, 30% or $37,500 was provided for CAP agency administration of the program. Approximately $57,965 was paid to HVAC contractors for their service, both costs were recognized as part of calendar

2019 activity. The cost per coupon averaged just over $373. The 2020 allotment was provided to the CAP agencies in late 2019 since the program followed the LIHEAP fiscal year of October 1 through September 30. No additional money was sent in 2020 and the only actual costs assigned to the program were in administrative labor. Historically, next year's allotment would have been provided in late 2020; however, due to Idaho Power and the CAP agencies moving the program to a calendar year, the allotment will be provided in early 2021.

In March 2020, due to the COVID-19 restrictions, in-home program activity was suspended in order to help keep contractors and customers safe. As a result, fewer coupons were redeemed in 2020 as compared to previous years. The funds that were not used to pay for redeemed coupons in 2020 will pay for additional tune-up coupons in 2021, when contractors start providing services for Idaho Power energy efficiency programs.

The planning committee found the original $300 maximum per coupon was frequently inadequate to address the costs associated with minor tuning and/or repairing of the heating systems and time to visit with customers. In 2019, the planning committee increased the coupon maximum to $600 and this amount was increased to $700 during 2020. This allowed contractors to spend extra time with customers and to travel further to rural areas. With the additional funds available per coupon, contractors agreed to give each customer 12 furnace filters.

Marketing Activities

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

Cost-Effectiveness

Because the Easy Savings program is primarily an educational and marketing program, the company does not apply traditional cost-effectiveness tests to it.

The Easy Savings HVAC coupon claimed 68.57 kWh of annual savings for each qualifying customer. The savings value is based on a simple average of the single-family and manufactured home-tune ups from the 2018 energy efficiency potential study. In 2021, the program will claim 68.01 kWh in savings from the 2020 energy efficiency potential study.

2021 Program and Marketing Strategies

The planning committee and participating regional HVAC contractors agreed to continue the Easy Savings program and to keep the maximum dollar amount available to contractors per customer visit at $700 when 12 filters are left with customer. This allows the HVAC contractor to make minor repairs to furnaces, air conditioners, and heat pumps while providing reimbursed time with the customer to review educational information.

Coupons for the 2021 program season will be distributed once services are safe to resume. CAP agencies will also receive helpful energy efficiency education materials to provide to regional HVAC contractors to share with customers.

Educational Distributions

		2020	2019
Participation and Savings			
	Participants (kits/giveaways)*	97,228	95,528
	Energy Savings (kWh) **	19,909,741	19,250,220
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	3,912,564	$2,989,184
	Oregon Energy Efficiency Rider	$91,912	$91,688
	Idaho Power Funds	$1,547	$0
	Total Program Costs—All Sources	$4,006,023	$3,080,873
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.037	$0.021
	Total Resource Levelized Cost ($/kWh)	$0.037	$0.021
Benefit/Cost Ratios* **			
	Utility Benefit/Cost Ratio	1.45	2.06
	Total Resource Benefit/Cost Ratio	2.19	3.32

*Participant counts do not include 2019 HER Pilot Program treatment size of 24,976, and 2020 HER program expansion treatment size of 127,138.

**2019 savings include HER Pilot Program savings for August 1, 2018–December 31, 2019. Savings in 2020 and forward are based on a calendar year.

***2020 cost-effectiveness ratios include evaluation. If evaluation expenses were removed from the program's cost-effectiveness, the UCT and TRC would be 1.48 and 2.23, respectively.

Description

Designated as a specific program in 2015, the Educational Distributions effort is administered through the REEEI 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 energy advisors.

Energy-Saving Kits

To make it easier for families to manage energy use, 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 nightlight, 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—one for the kitchen and two for bathrooms.

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, the company gives away the more basic version of the kit for homes with alternate-source water heaters; energy savings is garnered from lighting changes and not dependent on the source of water heat.

Home Energy Report Program

Idaho Power works with two third-party contractors to deliver the HER Program. The objective of the HER Program is to encourage customer engagement in regard to electricity use in order to produce average annual behavioral savings of 1 to 3%. Secondary objectives are to maintain or increase customer satisfaction and to encourage engagement with energy use, including online tools and participation in other energy efficiency programs.

The periodic reports provide customers with information about how their homes' energy use compares with similar homes. The *Home Energy Reports* also give a breakdown of household energy use and offer suggestions to help customers change their energy-related behaviors. The program contractor estimates energy savings that result from customers receiving the report by completing a statistical comparison of 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.

LED Nightlights as Giveaways

Nightlights are a popular giveaway item with Idaho Power customers and provide another opportunity to share information about energy efficient LED technology and safe, energy efficient ways to provide nighttime lighting. Energy advisors are encouraged to use nightlights as a bridge to these discussions.

Student Energy Efficiency Kit Program

The Student Energy Efficiency Kit (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 flipbook 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 2020, 39,667 kits were shipped to customer homes: 16,378 kits to homes with electric water heaters and 23,289 kits to homes with either alternate-source water heaters or those that had previously received a kit under a different account owner. 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 ready, 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: 38,571 to Idaho residences and 1,096 to Oregon.

Since program inception in June of 2016, Idaho Power customers have requested over 200,000 kits—representing just under a 50% saturation rate. In the past two years, organic participation has waned with almost all new sign-ups driven by the vendor's marketing efforts. After reviewing the future of lighting savings, the company proposed sunsetting the program in December of 2020. With EEAG's support, the program was officially closed on December 11, 2020 when the kit inventory at the warehouse was expended.

Energy-Saving Kits as Giveaways

Face-to-face events, presentations, and field staff interactions across Idaho Power's three regions were significantly curtailed as the company worked to safely comply with Idaho's COVID-19 guidelines. Even so, field staff found safe ways to deliver 100 kits to customers expressing the need for greater energy efficiency at home. Due to changes in cost-effectiveness and the sunsetting of the ESK program, these kits will not be available as a giveaway item in 2021.

Home Energy Report Program

Idaho Power, in collaboration with its contractors, transitioned the HER Pilot into a full-bodied program in June 2020.

The lessons learned from the pilot were applied and a new group of 106,941 treatment customers and a corresponding control group was formed. The new HER Program participants received a welcome letter and introductory report in early June, followed by regular bi-monthly reports in August, October, and December.

In addition, 20,197 of the previous pilot participants continued to receive quarterly reports in February, May, August, and November.

As with the pilot, the expansion 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% and allowing for approximately 15% attrition per year.

The savings results for the continuing participants that were in the pilot showed statistically significant estimated energy savings for the year to range from between 1.25% and 3.25%. In keeping with the company's commitment to optimize the savings and apply lessons learned, the lowest year-round users were removed from the treatment group prior to the expansion. The aggregate savings for continuing participants was 5,299 MWh across all groups. Between June 1 and December 31, the expansion participants used an average of 50.6 fewer kWh per home than their control group counterparts—a savings of 0.56%. The smaller saving percentage was expected for the expansion group as it generally takes about 6 months to ramp up savings. When viewed in aggregate, the estimated savings for all program participants was about 0.74% below their respective control groups, for a total of 10,428 MWh. On average, program participants are providing statistically significant savings at between 50 to 363 kWh annually per home.

Idaho Power's customer solutions advisors responded to 1,087 HER Program-related phone calls during the year. Given that 488,802 reports were delivered, this represents a call-rate of just under 0.22%. The participant-driven opt-out rate in in 2020 was 0.12%—significantly lower than the industry average of 1%. Overall attrition in 2020 was 9.4% (includes opt-outs, move-outs, etc.). No customer satisfaction survey was fielded in 2020; however, a process evaluation was conducted.

LED Lightbulbs as Giveaways

In 2020, Idaho Power energy advisors delivered educational messages and LEDs to attendees at the Idaho Remodeling & Design Show, the Canyon Home & Garden Show and several Lunch & Learns for local employers. Throughout the summer, the EOEAs worked closely with the senior centers to establish drive-through LED giveaway events. At these events, 3,550 LEDs were innovatively packaged with educational materials, energy-related activities, and well-wishes and given to seniors in the service area. In the fall, the EOEAs executed a second outreach effort, giving away LEDs and marketing virtual educational presentations in an effort to establish new connections with junior high and high school teachers.

By the end of the year, Idaho Power employees had safely delivered a brief energy efficiency message and distributed 10,250 lightbulbs directly to customers.

LED Nightlights as Giveaways

Early in 2020, the company approached EEAG to gain support for adopting nightlights as the newest educational distribution item. Although these devices are highly sought after by customers and have been a part of the kit programs for some time, the company had not previously claimed related savings. EEAG suggested the company should claim savings and that nightlights carry a visible statement "Uses LED technology." In addition, Idaho Power created an educational card that was developed to accompany the nightlights to further the conversation around energy efficient lighting practices.

By year-end, Idaho Power staff and energy advisors had distributed 4,965 nightlights along with an educational message.

Student Energy Efficiency Kit Program

During the 2019 to 2020 school year, recruiting activities for SEEK transitioned to the vendor, Franklin Energy. Idaho Power EOEAs continued to promote the program during their school visits and interactions with fourth to sixth grade teachers. Due to COVID-19 school closures early in 2020, the vendor stopped shipping program materials to schools in mid-March. By then, a number of teachers had received materials, but had not yet completed the program. The EOEAs made multiple personal contacts to offer support, to offer virtual delivery options, and to determine the status and plans for the remaining school year. Overall, the result of COVID-19 school closures was lower participation levels for the full school year and fewer student surveys returned. Despite COVID-19 related challenges during the winter/spring semester, Franklin Energy delivered 9,800 kits to 361 classrooms in 135 schools within Idaho Power's service area. This resulted in 1,880 MWh of savings.

Welcome Kits

Idaho Power continued to contract with a third-party vendor, Tinker Programs, to distribute a smaller energy efficiency kit for the company's brand-new customers. At the onset of 2020, materials included in the kit box were visually updated to align with current marketing materials. Although adjustments in kit contents were considered, the cost-savings did not justify making a change at that time.

The company sent nearly 32,500 Welcome Kits to customers in 2020—a slight increase over the quantity delivered in 2018 and 2019.

Idaho Power continues to receive positive customer feedback indicating these kits are well-received.

Marketing Activities

Energy-Saving Kits

Marketing efforts included two direct-mail campaigns from the kit vendor: one to about 221,300 customers in July and the final postcard, which utilized "last chance" language, to 10,000 customers in November. The July mailer was divided into two mailings: one for ordering kits online and the other for returning an order card by mail (known as a business reply card, or BRC). The conversion rate for direct-mailers declined from 18 to 20% in previous years to about 12.5% in 2020 due to the fact that most eligible customers had already received one or more invitations to participate.

Figure 9. Post card offering last chance to get a free ESK

Idaho Power sent ESK marketing emails to customers for the first time in April and October 2020. In April, an initial email was sent to 63,328 customers who hadn't yet ordered their kits. The initial email was then followed up with a remarketing email to those who didn't open the first email. The April remarketing email was sent a week later to 52,934 of the initial customers. This effort resulted in 7,141 customer visits to the ESK website, with 4,542 customers submitting an order. The initial October email, which used last-chance language, was sent to 114,604 customers with a follow-up remarketing email sent to 108,180 of those customers, resulting in 17,365 click throughs to the website and 10,445 kit orders. Accounting for approximately 15,000 new kit orders, the use of email marketing was an overwhelming success, especially considering it is a low-cost tactic.

Due to COVID-19, employees were not able to showcase ESKs at as many trade shows or other community events in 2020. But the kits continued to be popular items of discussion on Idaho Power's social media channels, with customers posting and writing comments thanking Idaho Power for the kit, encouraging friends and strangers to order their own, and asking questions about the ability to order more. Customers sharing how much they like and appreciate the kits is a strong marketing tool for Idaho Power.

Idaho Power
October 15, 2020 ·

Minnie's right! If you haven't already, order your FREE energy-saving kit before they're gone!

www.ipcsave2day.com

Minnie Marie is in Boise, Idaho.
October 14, 2020 ·

Awesome! Thank you Idaho Power For my free energy saving kit! It came with 9 led lightbulbs, 1 led night light, 1 refrigerater/freezer thermometer, 1 shower tim... See More

Figure 10. Customer post thanking Idaho Power for the free ESK

As the program wrapped up, Idaho Power used last-chance language on social media to encourage customers to order their kits before they were gone.

The kit was promoted to recipients of the *Home Energy Reports* in February/March (to those who hadn't already received a kit).

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 Program

Because the HER Program is based on the randomized control trial methodology, the reports cannot be requested by customers, therefore the program is not marketed. The periodic reports were, however, used to cross-market Idaho Power's other energy efficiency programs, with care taken to promote only those programs and offerings compatible with safety during the pandemic. My Account alerts and online activities received special callouts in 2020.

LED Lightbulbs as Giveaways

In 2020, as Idaho Power field activities paused for COVID-19 safety, staff and energy efficiency program specialists looked for new opportunities to safely distribute LEDs and educate customers. In the absence of one-on-one educational conversations between employees and customers at events, new educational activities and bookmarks were created to accompany the LEDs and to reinforce key concepts.

LED Nightlights as Giveaways

New in 2020, EOEAs also distributed LED nightlights, complete with a new educational card to help promote its efficiency and cost-savings. The majority of the 2020 distributions were to seniors across the service area—with an emphasis on rural communities.

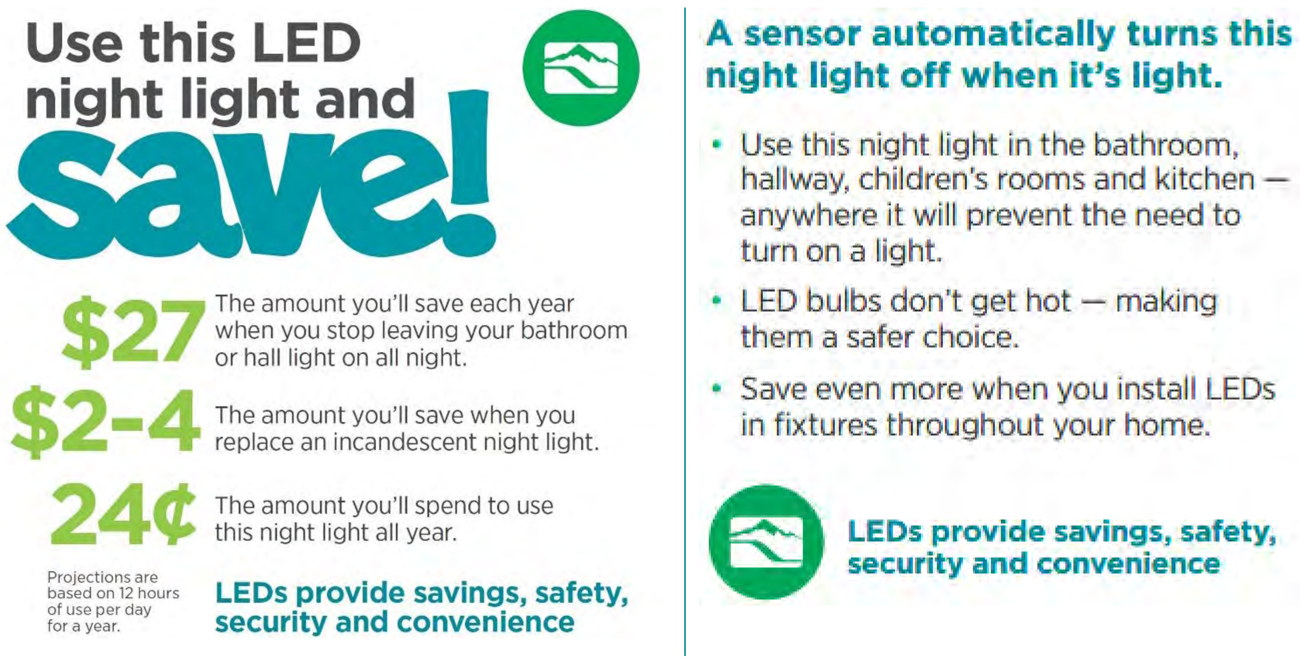

Figure 11. LED nightlight education card

Student Energy Efficiency Kit Program

During the 2019-2020 school year, Franklin Energy staff handled most of the marketing and recruitment of teachers via email and phone calls to the eligible schools. Idaho Power EOEAs continued to promote the program through the *Community Education Guide* and in conversations with teachers throughout the year.

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 to fulfill the order. However, the kits are used to cross-market other programs through the inclusion of a small flipbook containing energy-saving tips and information about Idaho Power's energy efficiency programs.

Cost-Effectiveness

In situations where Idaho Power managed 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.

The UCT and TRC for the program is 1.45 and 2.19 respectively. If the amount incurred for the 2020 evaluation was removed from the program's cost-effectiveness, the UCT would be 1.48 while the TRC would be 2.23.

Energy-Saving Kits

The RTF provides mail-by-request deemed savings for LED lightbulbs, faucet aerators, and the integrated high-efficiency showerheads with a TSV. The RTF mail-by-request deemed savings values are discounted to reflect the potential that not all the kit items may be installed. The LED lightbulbs each have a deemed savings value of 6.97 kWh per year. The by-request faucet aerator savings are 36.84 kWh when installed in a kitchen and 22.08 kWh when installed in the bathroom. For the integrated 1.75 gallon per minute (gpm) low-flow showerhead with TSV, the RTF assumes an installation rate of 90%. Based on Idaho Power's follow-up survey results, it appears the installation rate is approximately 57%. For 2020, the Idaho Power adjusted the savings to be 114.72 kWh annually.

Historically, Idaho Power did not claim the savings for the nightlights included in the ESK. After discussing the potential of claiming nightlight savings with EEAG, Idaho Power requested that the nightlight savings associated with the kits be researched as part of the 2020 evaluation. After surveying customers, the evaluator calculated that Idaho Power could claim 12 kWh per nightlight.

The annual savings for an ESK for a home with an electric water heater is approximately 270 kWh. The annual savings for a kit for a home with a non-electric water heater is approximately 75 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 6.97 kWh per bulb. The annual savings for each giveaway kit is approximately 75 kWh.

Home Energy Report Program

HER Program savings are calculated by the program implementers through an internal evaluation. Savings for the 2020 program year are calculated at 10,427,940 kWh. A net-to-gross (NTG) factor of 95% is applied at the measure cost-effectiveness level to account for potential double counting of savings. Double counting occurs when a customer participates in another energy efficiency program due to their participation in the HER Program. The offering was not cost-effective for 2020 largely due to the additional costs associated with the expansion of the program. Additionally, the savings associated with the expansion only reflect a partial year of savings and it generally takes six months to ramp up savings. It is anticipated that the program will be cost-effective in future years even while claiming a one-year savings life.

LED Lightbulbs and Nightlights as Giveaways

For the LED giveaways, Idaho Power used the giveaway deemed savings provided by the RTF. The RTF-deemed annual savings of 6.97 kWh includes assumptions regarding the installation rate, efficiency levels of the existing lightbulb, and the location of the installation. For nightlights, Idaho Power used the DNV GL calculated savings of 12 kWh as explained in the ESKs cost-effectiveness section.

Student Energy Efficiency Kit Program

The cost-effectiveness analysis for the SEEK offering was based on the savings reported by the kit provider during the 2019 to 2020 school year. The kit provider 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 31%. 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 2019 to 2020 school year the savings for each kit was approximately 192 kWh annually per household on average, and the program saved 1,879,542 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 use the RTF's giveaway deemed savings value of 6.97 kWh per bulb. For the nightlight, Idaho Power used the DNV GL calculated savings of 12 kWh per nightlight as explained in the ESKs cost-effectiveness section. The annual savings for each kit is 39.88 kWh.

Evaluations

In 2020, Idaho Power contracted with DNV GL to conduct an impact and process evaluation on the Educational Distributions program and process evaluation for the HER Program. The Educational Distributions impact evaluation calculated an overall savings realization rate of 97% and a realization rate for the count of kits delivered of 100%. The savings realization rates for Welcome Kits, Energy-Saving Kits, and SEEK was 100%, 97%, and 97% respectively.

The evaluation found a well-run program with satisfactory processes and satisfied customers. A Welcome Kit participant survey was completed and concluded 12 kWh savings could be claimed for each nightlight included in the kits.

Idaho Power will consider any recommendations and responses will be reported in the *Demand-Side Management 2021 Annual Report*. See the complete analysis report in *Supplement 2: Evaluation*.

The HER Program process evaluation was started alongside the Educational Distributions evaluation. However, due to some late findings, additional analysis was required to complete the evaluation. The evaluation report will be completed in April 2021 and will be included in the 2021 annual report.

2021 Program and Marketing Strategies

Idaho Power conducted an impact and process evaluation for the Educational Distributions program and a process evaluation for the HER Program in 2020. Actionable recommendations were either implemented in 2020 or will be addressed in 2021 and discussed in the 2021 DSM Report.

Home Energy Report Program

Idaho Power will continue to deliver *Home Energy Reports* to active program participants on a quarterly schedule with reports arriving in February, May, August and November. Participants with usage tied to high A/C use or winter heating will receive seasonal reports in either May or November, as appropriate.

Idaho Power has committed to upgrading the software platform, which should provide opportunities to enhance the current *Home Energy Report* template and/or messaging. As new options become available, the company will actively assess them with an eye toward improving savings and enhancing the customer experience.

LED Nightlights as Giveaways

Nightlights will be the primary opportunity to garner savings in conjunction with educational discussions and customer conversations. Field staff will look for opportunities to discuss LED technology and savings, encourage in-home adoption of LED lighting, and promote the use of LED nightlights as an energy efficient, safe nighttime lighting option.

Student Energy Efficiency Kit Program

Idaho Power will continue to offer the SEEK program and plans to review the materials and pricing to ensure the program remains competitive in the marketplace.

The company will continue to leverage the positive relationships Idaho Power's EOEAs have within the schools to maintain program participation levels. Adjustments may be made in the marketing and delivery processes based on kit pricing and vendor recommendations and capabilities.

Welcome Kits

In 2021, due to new RTF savings for lightbulbs, the kits will no longer be cost-effective as a stand-alone item. However, 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, and their cost will be included as part of Idaho Power's energy efficiency promotion efforts. Idaho Power does plan to count what little savings that can be claimed from the items in the kits.

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. The company is currently exploring options that may provide some customers with access to items formerly available through the ESK Program.

Energy Efficient Lighting

		2020	2019
Participation and Savings			
	Participants (lightbulbs)	1,148,061	1,336,440
	Energy Savings (kWh)	13,942,202	16,245,551
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,603,129	$2,026,977
	Oregon Energy Efficiency Rider	$62,218	$99,285
	Idaho Power Funds	$1,812	$0
	Total Program Costs—All Sources	$1,667,159	$2,126,262
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.012	$0.011
	Total Resource Levelized Cost ($/kWh)	$0.022	$0.014
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.56	4.04
	Total Resource Benefit/Cost Ratio	4.20	5.17

Description

Idaho Power and other regional utilities participate in the BPA-sponsored Simple Steps, Smart Savings™ program, managed by a third-party contractor. Idaho Power promotes Simple Steps, Smart Savings™ offerings to customers in two areas: this Energy Efficient 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 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% less energy and last 10 to 25 times longer than traditional incandescent lightbulbs.

Idaho Power pays the program contractor 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, marketing, and 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, the program contractor is responsible for contracting with retailers and manufacturers, providing marketing materials at the point of purchase, and supporting and training retailers.

Program Activities

In 2020, LED lightbulbs comprised 93% of the program's sales for the year, a slight decrease from the 94% of lightbulb sales in 2019. LED fixtures comprised approximately 7% of overall program sales.

In 2020, through the BPA Simple Steps, Smart Savings™ program, Idaho Power worked with 13 participating retailers, representing 99 individual store locations in its service area. Of those participating retailers, 54% were large retailers and 46% were smaller grocery, drug, dollar and hardware stores. Many rural sales came from these smaller retailers that serve hard-to-reach customers. It is important to include a variety of store types across the Idaho Power service area to ensure all customers have access to the Simple Steps qualified products.

In 2019, BPA announced they would no longer sponsor the Simple Steps promotion after September 30, 2020. The decision to end the program was based on the lighting market transformation to high-efficiency lightbulbs. Idaho Power continued participation in the Simple Steps program until September 30.

Marketing Activities

In 2020, the program contractor promoted discounts with special product placement and signs. Due to COVID-19 restrictions and to ensure the safety of field staff and customers, the program contractor did not perform any lighting events in 2020. Monthly visits to check stock, point-of-purchase signs, and displays were suspended from March 26 to September 1, when field staff returned to stores to remove point-of-purchase information and to remind store staff and management that the program was ending.

In the first few months of 2020, at 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 qualified products.

The company continued to host an Energy Efficient Lighting program website and made available a *Change a Light* program brochure. The brochure is distributed at community events to help discuss energy-efficient lighting with customers and to help them select the right lightbulb for their needs. Several social media posts throughout the year also focused on energy-efficient lighting. Idaho Power recommended using ENERGY STAR® LED lightbulbs in its spring *Energy Efficiency Guide*; the January and July issues of *Connections*; and the March, September, and November *Home Energy Reports*.

The Simple Steps, Smart Savings™ program was removed from the Idaho Power website on September 30, 2020.

Cost-Effectiveness

In 2019, the Energy Efficient Lighting program provided 37% of all energy savings derived from residential energy efficiency customer programs and almost 8% of Idaho Power's direct program savings. Between 2019 and 2020, bulb sales and savings declined nearly 14% largely due to the sunsetting of the Simple Steps promotion by BPA on September 30, 2020.

In November 2018, 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 practice market baseline for lightbulbs. Due to the timing of the RTF's update, BPA and the contractor implemented these savings in 2020 in the Simple Steps, Smart Savings™ promotion. The RTF LED workbook version 7.1 was the source of most lighting savings assumptions throughout Idaho Power's residential program offerings.

The annual savings for the most popular bulb type, the general-purpose lightbulb in the 250–1049 lumen range, decreased from 12 kWh to about 9 kWh. This bulb type made up almost 49% of the total bulbs sold in the program and approximately 37% of the total savings. Due to the decrease of per-unit savings and the sunsetting of the program, the total savings for this bulb type decreased by just over 2.9 million kWh between 2019 and 2020.

The second most popular bulb type is the reflector lightbulb in the 250–1049 lumen range, which is commonly used in recessed canned light fixtures. The RTF increased the per-bulb savings for this bulb type from 8 kWh to 11 kWh. These reflector bulbs made up almost 17% of the total lightbulbs sold in the program and nearly 16% of the total savings. Between 2019 and 2020, the 250–1049 lumen reflector lightbulb sales remained relatively steady. With the increase in deemed savings, the total savings for this bulb type increased approximately 437,000 kWh between 2019 and 2020.

The RTF reviewed and approved new savings for LEDs in September 2019 and again in September 2020. Idaho Power is monitoring how utilities in the region plan to incorporate the latest RTF numbers.

The UCT and TRC ratios for the program are 4.56 and 4.20 respectively.

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

2021 Program and Marketing Strategies

Idaho Power is researching options for a new lighting buydown program similar to the Simple Steps program. The redesigned program would offer incentives at grocery, dollar, and mass merchant stores because studies have found a higher percentage of inefficient lighting products are currently sold through these retail chains. Additionally, these types of stores are typically in more rural areas. A redesigned program would allow additional Idaho Power customers to participate in a cost-effective, energy efficiency program.

Energy House Calls

		2020	2019
Participation and Savings			
	Participants (homes)	51	248
	Energy Savings (kWh)	56,944	309,154
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$40,492	$143,570
	Oregon Energy Efficiency Rider	$5,422	$18,324
	Idaho Power Funds	$438	$0
	Total Program Costs—All Sources	$46,352	$161,894
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.075	$0.039
	Total Resource Levelized Cost ($/kWh)	$0.075	$0.039
Benefit/Cost Ratios*			
	Utility Benefit/Cost Ratio	0.63	0.96
	Total Resource Benefit/Cost Ratio	0.77	1.30

*2019 cost-effectiveness ratios include evaluation expenses. If evaluation expenses were removed from the program's cost-effectiveness, the UCT and TRCs would be 1.11 and 1.49, respectively.

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 response to COVID-19 restrictions and to ensure the safety of customers and contractors, no Energy House Calls visits were completed from March 16 through the end of 2020. Prior to March, 51 homes received products and/or services through this program, resulting in 56,944 kWh savings (Figure 12). In 2019, during the same period, 56 customers received products and or/services.

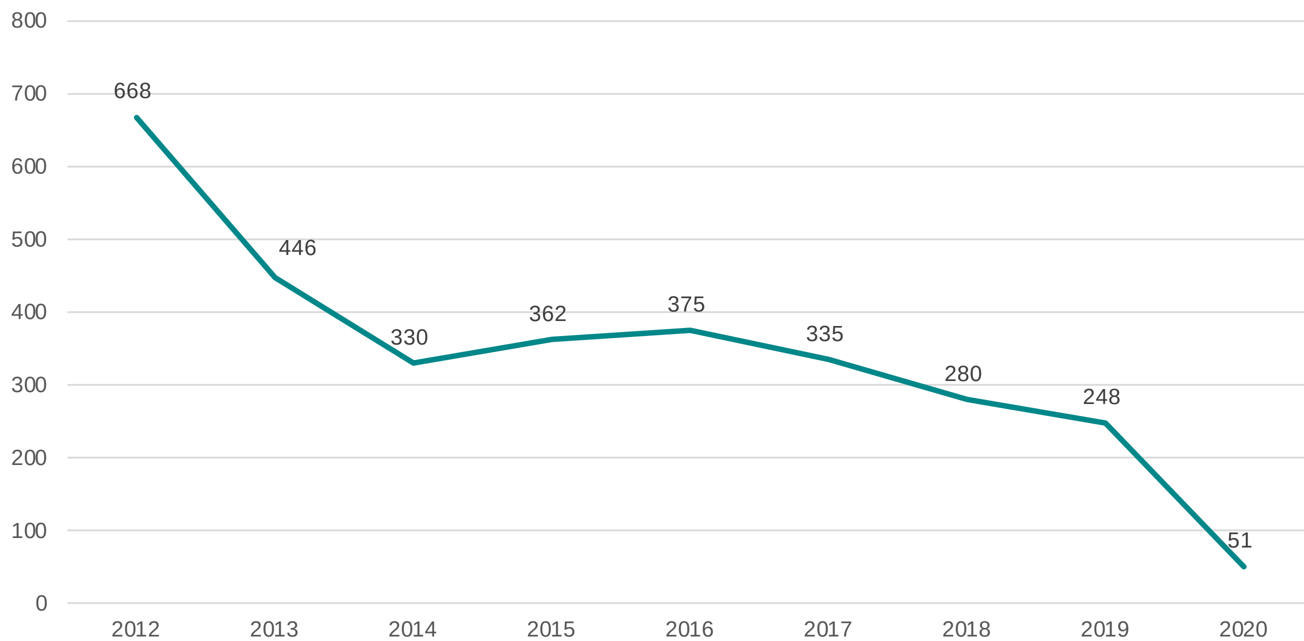

Figure 12. Participation in the Energy House Calls program, 2012–2020

Of the total participating homes, 57% were located in the Canyon–West Region, 18% were located in the Capital Region, and 25% were located in the South–East Region.

Findings from the impact evaluation performed in 2019 found that Idaho Power had been using heating zones based on cities rather than zip codes to determine PTCS duct-sealing savings. For 2020, Idaho Power applied the duct-sealing savings using the heating zones associated with the zip codes of the participants. It was also discovered that Idaho Power was using a per-faucet savings value for aerators rather than a household value. Idaho Power had already transitioned to the RTF-deemed savings in 2019 prior to receiving the evaluation, so the household value versus the per faucet aerator value is no longer an issue.

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%, 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 they included no kWh savings. 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 51 homes that participated in 2020, five 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 is billed as a test and seal. For a multi-section 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 is 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 is billed as a complex system. A complex system that also requires the installation of a new x-over and duct sealing is billed as a complex system and x-over job.

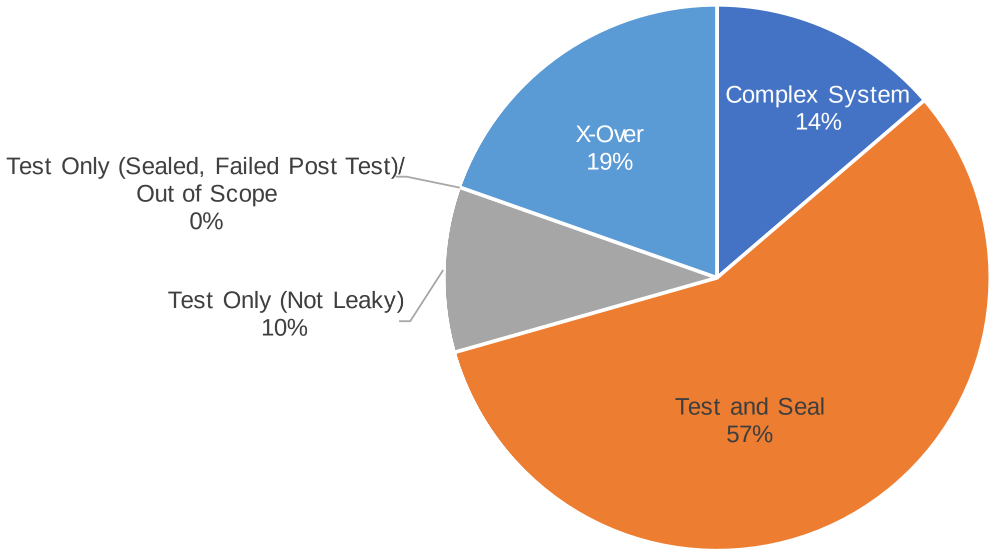

Figure 13. Energy House Calls participation by job type

Direct-Install Measures

In 2020, contractors installed 200 LED lightbulbs, 11 showerheads, six bathroom aerators, and nine kitchen aerators. Contractors noted that they've seen a decrease in direct-install measures, as customers have commented they have already installed the provided products after receiving free ESKs from Idaho Power. Of the 51 homes that participated in the program in 2020, 49% had received an ESK at some point in the past.

Marketing Activities

In February, Idaho Power sent a postcard to residents who lived in electrically heated manufactured homes that had not yet participated in the program. Written in English and Spanish, 9,010 postcards were delivered in February. In April, the company sent a bill insert to 309,763 residential customers in Idaho and Oregon. The bill insert was shared with the Rebate Advantage program. Customers who requested an Energy House Call visit after March 16, 2020, were added to a wait list and will be contacted to schedule a visit when COVID-19 restrictions are lifted.

To help alleviate any potential customer dissatisfaction, the company cancelled these scheduled program-related outreach efforts: the June Facebook ad and email, the July postcard, and the December bill insert. The December bill insert was replaced with one that provided DIY winter home energy efficiency tips applicable to all types of home or apartment owners or renters. Additionally, Idaho Power added an alert to the Energy House Calls webpage to let customers know of the suspension of in-home program work and the delay for scheduling home visits.

Cost-Effectiveness

In 2020, Idaho Power used the same RTF savings for duct-sealing and low-flow faucet aerators in manufactured homes as were used in 2019. Savings and a cost-effectiveness analysis for the other direct-install measures, low-flow showerheads and LED lightbulbs, were completed using updated deemed savings from the RTF.

The UCT and TRC ratios for the program are 0.63 and 0.77, respectively. The program's cost-effectiveness was impacted by the suspension of in-home visits due to COVID-19. The company will continue to monitor this program and will explore opportunities to further improve the program's cost-effectiveness in 2021.

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

2021 Program and Marketing Strategies

Once COVID-19 safety protocols allow, 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 long as it remains cost-effective to do so. 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 emails, and use social media and other proven marketing strategies to encourage customer participation. Contractors and energy advisors 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

	2020	2019
Participation and Savings		
Participants (projects)	1,019	681
Energy Savings (kWh)	1,839,068	1,412,343
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$578,893	$478,560
Oregon Energy Efficiency Rider	$23,978	$20,619
Idaho Power Funds	$3,689	$0
Total Program Costs—All Sources	$606,559	$499,179
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.033	$0.028
Total Resource Levelized Cost ($/kWh)	$0.103	$0.084
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.66	1.56
Total Resource Benefit/Cost Ratio	0.81	0.77

Description

Initiated in 2007, the objective of the Heating & Cooling Efficiency (H&CE) Program is to provide customers with energy-efficient options for space heating and cooling and water heating. The program provides incentives to residential customers, builders, and installation contractors in Idaho Power's service area for the purchase and proper installation of qualified heating and cooling equipment and services.

Measures, Conditions, and Incentives/Stipends for Existing Homes

- Ducted air-source heat pump:
  - 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). A $50 stipend is paid to the participating contractor.
  - 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. A $50 stipend is paid to the participating contractor. 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. A $50 stipend is paid to the participating contractor.
- Ducted open-loop water-source heat pump:
  - 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). A $50 stipend is paid to the participating contractor.
  - 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. A $50 stipend is paid to the participating contractor.

- Ductless air source heat pump: The customer incentive for displacing a zonal electric heating system with a new ductless air source heat pump is $750.
- Duct sealing: 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.
- Electronically commutated motor (ECM): The customer incentive for replacing a permanent split capacitor (PSC) air handler motor with an 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. A $150 incentive is paid to the licensed contractor.
- Evaporative cooler: The customer incentive for installing an evaporative cooler is $150.
- Heat pump water heater (HPWH): The customer incentive for installing a HPWH is $300.
- Smart thermostat: The customer incentive for a smart thermostat installed in an existing home with an electric forced-air furnace or a heat pump is $75.
- Whole house fan: 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.

Measures, Conditions, and Incentives/Stipends for New Homes

- Ducted air-source heat pump: The incentive for homeowners, property owners, 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. A $50 stipend is paid to the participating contractor. Participating homes must be located in areas where natural gas is unavailable.
- Ducted open-loop water-source heat pump: The incentive for homeowners, property owners, 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. A $50 stipend is paid to the participating contractor. Participating homes must be located in areas where natural gas is unavailable.

Idaho Power requires licensed contractors to perform the installation services related to all of these measures, except evaporative coolers, HPWH, and smart thermostats. To qualify for the heat pump and duct-sealing incentive, an authorized participating contractor must perform the work. To be considered a participating contracting company, an employee from the contracting company must first complete Idaho Power's required training regarding program guidelines and technical information on HVAC equipment.

Honeywell, Inc., a third-party contractor, reviews and submits incentive applications for payment using a program database portal developed by Idaho Power. Honeywell also provides technical and program support to customers and contractors and performs on-site and off-site verifications.

Program Activities

In 2020, Idaho Power conducted research and activities to improve customer participation and satisfaction in the H&CE Program. An exercise, described as journey mapping, was completed by a dedicated team from multiple departments who met periodically for three months to challenge, discuss, and modify elements of the program in detail. The purpose of the exercise was to identify difficulties customers might experience when participating in the program. The primary elements identified for revision included website content and application forms. Idaho Power updated its website in 2020 and expects to complete revising the application forms in 2021.

Idaho Power relies, in part, on the RTF to determine the energy savings values it claims for the smart thermostat measure. However, when the RTF announced it would no longer support their savings calculations for the smart thermostat measure, Idaho Power and other stakeholders launched a regional Smart Thermostat Research Study to provide regional smart thermostat performance data to the RTF. The study began in November 2019 and will extend into 2021. Because of the regional study, the RTF extended the period it would support the savings estimates to December 31, 2021.

Idaho Power continued work to improve penetration in the ductless heat pump (DHP) market for homes heated with electric zonal systems. For example, Idaho Power and NEEA provided product and application training to HVAC contractors across the company's service area. The company offered six online training sessions in October and November 2020. Each was met with appreciation by the attendees.

The 2020 H&CE Program paid incentives are listed in Table 11.

Table 11. Quantity of H&CE Program incentives in 2020

Incentive Measure	Project Quantity
Ducted Air-Source Heat Pump	161
Open Loop Water-Source Heat Pump	6
Ductless Heat Pump	244
Evaporative Cooler	9
Whole-House Fan	129
Electronically Commutated Motor	51
Duct Sealing	1
Smart Thermostat	393
Heat Pump Water Heater	25

Honeywell performed random off-site verifications on 5% of the completed installations. This year, the verifications were performed via phone due to COVID-19 restrictions. These verifications confirmed the information submitted on the paperwork matched what was installed at customers' sites. Overall, the verifications results were favorable.

Supporting, developing, and expanding Idaho Power's authorized participating contractor network remained a key growth strategy for the program. In 2020, company representatives met with many prospective contractors to support this approach. As a result, Idaho Power added 13 new contractors to the program in 2020.

Marketing Activities

Idaho Power used multiple marketing methods for its H&CE Program in 2020, focusing efforts toward the hottest and coldest times of the year.

Idaho Power sent two program-related postcards to a targeted customer group that uses electric heat: 8,188 customers in February and 8,132 customers in September. The company mailed a bill insert to 321,081 residential customers in April and 365,038 residential customers in September.

In February, the company emailed information about the H&CE Program to approximately 197,000 residential customers. Over the next three days, the program web page received 5,543 unique page views, which is a large increase compared to the 376 total page views during the three days prior to the email.

In February and September, Idaho Power used an ad agency to send digital display ads to customers based on their internet browsing preferences. Using Google Analytics, the ad agency determined the ads resulted in 2,894,645 impressions and 8,508 clicks to the H&CE Program web page in February and 3,137,679 impressions and 10,327 web clicks in September. In addition to digital display ads, the company used remarketing ads in September targeting customers who had previously visited the H&CE Program web page. The ads resulted in 3,362 impressions with 50 clicks to the web page. A September Facebook ad resulted in 215,758 impressions and 1,766 click throughs to the H&CE Program web page.

Idaho Power used several social media posts throughout 2020 focused on tips related to home heating and cooling. DHPs were prominently featured in the company's overall energy efficiency campaign that ran in a variety of mass-media locations. Additionally, in February, a link from the company's website homepage directed customers to its smart thermostat web page and in September a link directed customers to the H&CE Program web page.

The company held a smart thermostat giveaway at the January *Idaho Remodeling & Design Show* and promoted the program on the trade show booth panels. Program information was also included in energy efficiency collateral mailed in the new customer Welcome Kits.

The company used several PR tactics to promote the program, including interviews touting smart thermostats on KTVB and KMVT in February. Smart thermostats were also promoted in a *News Brief* in January. A smart thermostat article was featured in the February edition of *Connections*. The summer edition of the *Energy Efficiency Guide* distributed through local newspapers featured articles on smart thermostats and HPWHs.

Additionally, the program specialist continued to distribute flyers, called tech sheets, to interested customers and contractors. The eight different flyers are especially beneficial as sales tools for contractors, for use at trade shows, and as mailers to customers without internet access who seek program and individual cash incentive information.

Cost-Effectiveness

The H&CE Program has a utility cost test of 1.66 and total resource cost test of 0.81. The increase in UCT and TRC over 2019 is largely due to the increase in participation in the program.

The savings assumptions for most measures including air source heat pumps, open-loop water-source heat pump, DHPs, and duct sealing remain unchanged from 2019. All measures within the program pass the UCT except for heat pump upgrades and smart thermostats. However, the measures would pass the UCT if administration costs were not included in the measure's cost-effectiveness. A handful of measures, such as DHPs and open-loop water-source heat pumps are not cost-effective from a TRC perspective. These measures and the program itself have cost-effectiveness exceptions with the OPUC under UM 1710.

In late 2019, the RTF updated the assumptions around heat pumps and recalibrated their model based on empirical data from evaluations and research throughout the northwest which resulted in a reduction of per unit savings. These savings will be applied to the program in 2021. At the same meeting, the RTF voted to deactivate the savings for the commissioning, controls, and sizing (CCS) of the heat pumps. The CCS savings are additive to the air-source heat pump conversion and upgrade measure and assumes the proper installation of the heat pumps based on BPA's PTCS standards. While the analysis suggests that there could be meaningful savings for utilities especially east of the Cascades, some utilities did not follow BPA's PTCS standards. In discussing the CCS savings with the program engineer, Idaho Power does follow the PTCS standards. Idaho Power plans to continue using the CCS savings in 2021 and will use the upcoming program evaluation as an opportunity to do further research on this measure.

In 2020, Idaho Power updated the savings for evaporative coolers. Previously, Idaho Power cited the evaporative coolers savings from past potential studies. After further research, it was determined that the savings were modeled on the replacement of an existing evaporative cooler. However, the program engineer believes the measure encourages the displacement of whole house existing mechanical cooling. Mechanical cooling is shut off during variable outdoor conditions where an evaporative cooler can cool the room. After researching available technical reference manuals (TRM), Idaho Power found the New Mexico TRM had a reasonable deemed savings value based on a variety of representative cities and their associated cooling degree days. As part of the 2021 program evaluation, Idaho Power plans to have the evaluators check the reasonableness of these values and provide an updated savings value based on Idaho Power climate zones.

In early 2021, RTF reviewed and updated the savings assumptions for HPWHs. While it is Idaho Power's position to freeze savings assumption during budgeting, the newest HPWH workbook includes savings for the Tier 4 HPWH. The Tier 3 models are slowly leaving the market and are being replaced with Tier 4 models. To begin claiming savings for these HPWHs, Idaho Power will need to adopt the newest workbook for 2021.

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

2021 Program and Marketing Strategies

Idaho Power will contract with a third party to conduct process and impact program evaluations in 2021.

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. 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 participating contractors 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 2021 is to develop contractors currently in the program while adding new contractors. To meet this objective, the program specialist will frequently interact with contractors in 2021 to discuss the program.

The 2021 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.

Home Energy Audit

		2020	2019
Participation and Savings			
	Participants (homes)	97	421
	Energy Savings (kWh)	31,938	179,754
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$128,547	$230,786
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$1,999	$0
	Total Program Costs—All Sources	$130,546	$230,786
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.448	$0.122
	Total Resource Levelized Cost ($/kWh)	$0.449	$0.150
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Under the Home Energy Audit program, a certified, third-party home performance specialist conducts an in-home energy audit to identify areas of concern and 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 auditor writes up the findings and recommendations, and the software creates a report 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 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 available to install in each home is approximately $145.

Each year, the quality assurance (QA) goal for the program is to inspect 5% of all audits.

Program Activities

Three home performance specialist companies served the program in 2020 and completed 97 energy audits. House size ranged from 528 square ft (ft^2) to 7,400 ft^2, with the average size of 2,314 ft^2. Houses were built from 1908 to 2019, with the average age of 40 years old.

Due to COVID-19 restrictions, Idaho Power suspended audits in mid-March 2020 through the end of the year. This greatly impacted the number of audits completed and associated savings. The company continued to accept enrollments and contacted customers to explain the delay.

Figure 14 depicts the program's reach across Idaho Power's service area, and Figure 15 depicts the space and water heating fuel types. Figure 16 indicates the total quantity of direct-install measures.

Because in-home activity was suspended most of the year, QAs were not performed.

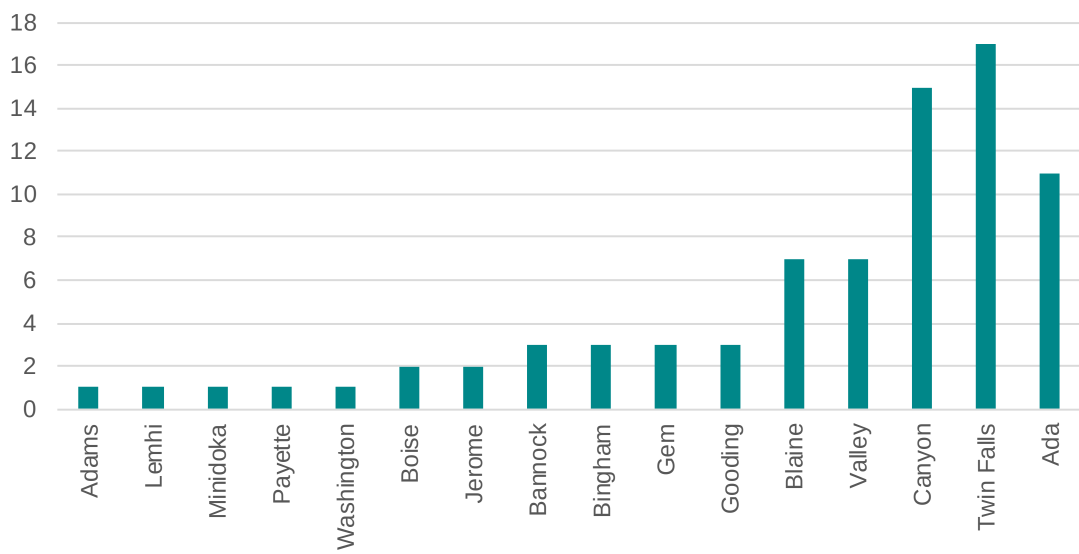

Figure 14. Home Energy Audit summary of participating homes, by county

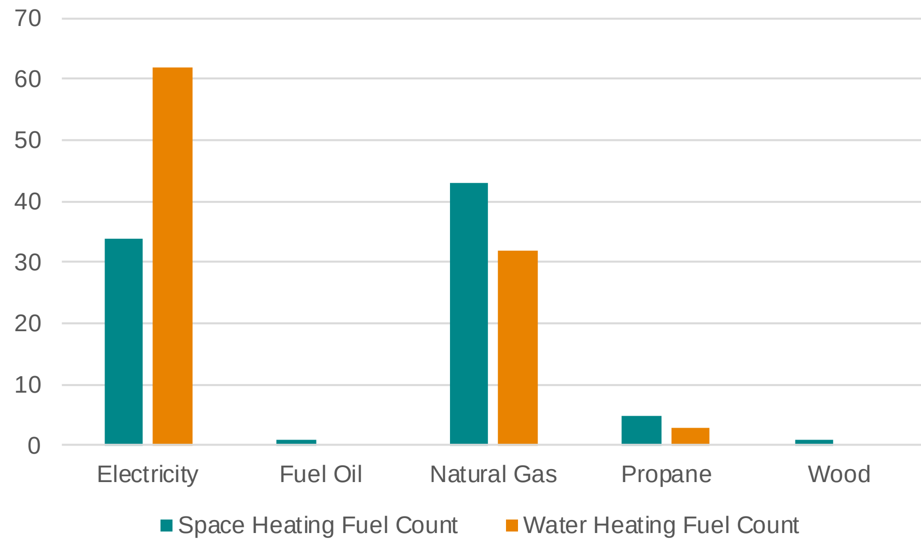

Figure 15. Home Energy Audit summary of space and water heating fuel types

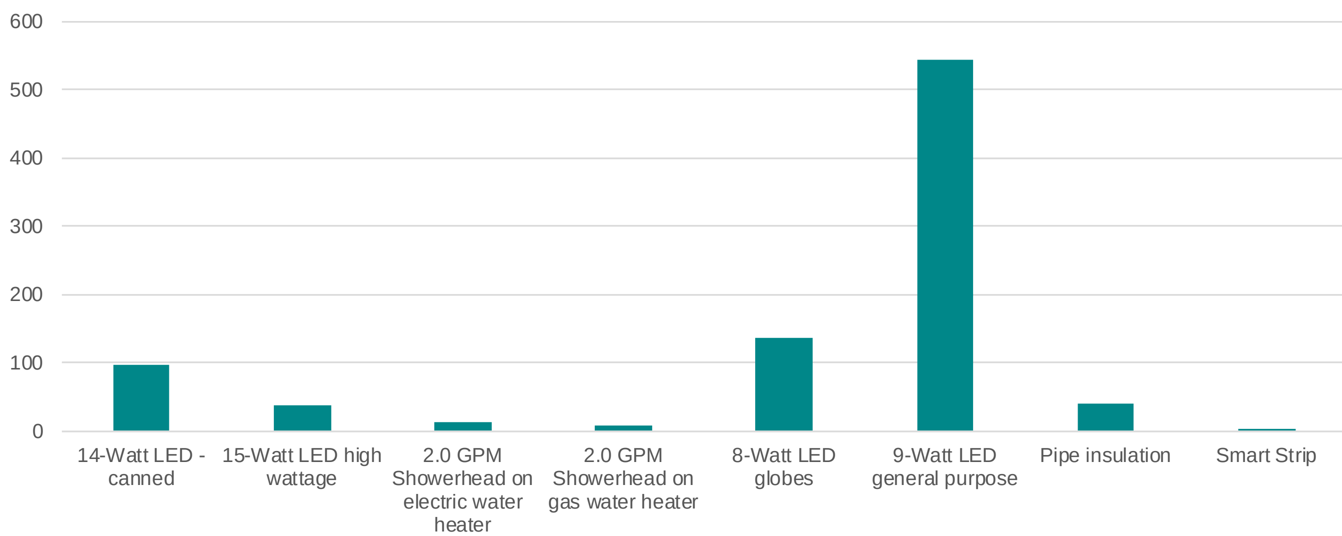

Figure 16. Number of Home Energy Audit measures installed in participating homes

Marketing Activities

In early 2020, Idaho Power recruited participants using small batches of direct mail letters to ensure customers who signed up were contacted within a short timeframe and to avoid a large backlog of work that could result in a poor customer experience. Due to COVID-19 restrictions, Idaho Power suspended this marketing effort in mid-March.

In November, Idaho Power collaborated with the University of Idaho's Valley County Extension Office to host a virtual energy efficiency workshop for customers in Valley county. The company sent letters and emails and used a Facebook post to invite residents to attend the evening workshop. Forty residents registered for the workshop, and twenty attended the well-received workshop. This is twice the number that attended last year's in-person event.

Attendees learned how to check their homes for efficiency, how to make some improvements, what incentives are available through Idaho Power, and how a professional energy assessment could help improve energy efficiency. The company conducted a random drawing to give away four LED nightlights to attendees. A local energy advisor delivered the nightlights to customer's front porches while social distancing and wearing a mask. Customers expressed appreciation during the event for being able to have the workshop despite COVID-19 restrictions.

Idaho Power sent program-related bill inserts to 310,836 residential customers in March, 308,036 customers in July, 304,066 in September, and 296,947 customers in December. The company included new messaging to let customers know they would be signing up for a waitlist since auditors were unable to conduct in-person visits.

In February and March, targeted digital display ads ran on a variety of websites based on user demographics, search behavior, and other factors. The ads generated 940,774 impressions and a 0.22% click-through rate. In March, a Facebook post about the program was boosted, resulting in 4,785 impressions.

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, 39.1%; family member or friend, 8.27%; Idaho Power employee, 11.65%; social media, 3.01%; other, 37.97%.

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. Because 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 46 kWh per year. This was a slight decrease over the 2019 lightbulb savings which ranged from 16 to 52 kWh per year.

In Idaho Power's *Energy Efficiency Potential Study*, it is estimated that pipe wraps save 78 kWh per year. Showerhead savings were updated in 2020 using the RTF version 4.3 workbook. Savings for both showerheads and pipe wrap were counted for homes with electric water heaters.

As recommended in a previous evaluation, non-energy benefits (NEB) have been determined 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 78 kWh of pipe wrap savings to 2.66 therms and those gas savings are included in the sector and portfolio cost-effectiveness.

2021 Program and Marketing Strategies

Once COVID-19 safety protocols allow for audits to resume, 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.

Multifamily Energy Savings Program

	2020	2019
Participation and Savings		
Participants (projects [buildings])	33 [4]	457 [12]
Energy Savings (kWh)	28,041	346,107
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$83,951	$115,560
Oregon Energy Efficiency Rider*	$4,350	$15,745
Idaho Power Funds	$1,528	$0
Total Program Costs—All Sources	$89,829	$131,306
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.372	$0.036
Total Resource Levelized Cost ($/kWh)	$0.372	$0.036
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	0.14	1.15
Total Resource Benefit/Cost Ratio	0.28	2.34

* 2018 Idaho Rider charges of $13,264 were reversed and charged to the Oregon Rider in March 2019.

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, Idaho Power pre-approves each building and the contractor who will install the energy efficiency measures. Upon approval, the no-cost, direct installation is scheduled, and a tailored door hanger is placed on tenants' apartments to explain the schedule and process of the installation.

Program Activities

Due to COVID-19 restrictions, Idaho Power suspended in-home activity on March 16, 2020, and it remained suspended through the end of the year. This resulted in a substantial decrease both in the number of units completed and energy savings.

Prior to the suspension, the company completed four projects (33 apartments) in Idaho. No projects were completed in Oregon.

The company is still accepting applications and has identified apartment complex owners/managers who are interested in participating in the program. Once COVID-19 restrictions are lifted owners/managers will be contacted and installs will be scheduled.

Marketing Activities

Idaho Power continued to run three alternating, clickable ads on its Landlord/Property Manager Requests web page that linked users to the Multifamily Energy Savings Program web page.

A marketing video placed at the top of the Multifamily Energy Savings Program web page also continued to run in 2020. 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 to be more comfortable in their homes. At the end of the video, company contact information is provided.

In January, Idaho Power placed a print ad promoting the program in the *Idaho Business Review's* special *Multifamily Residential* section. The ad featured updated imagery to match the refreshed look of the company's energy efficiency marketing collateral.

Idaho Power communicated with participants before and after installation. In addition to the pre-installation door hanger, the contractor 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 company uses these responses to help improve future marketing activities.

Cost-Effectiveness

The RTF provides deemed savings for direct-install LED lightbulbs, low-flow showerheads, and faucet aerators. The LED lightbulbs have a deemed savings value of 16.17 to 83.87 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 197.80 kWh per year. Faucet aerators installed in a kitchen have a deemed annual savings value of 43.94 kWh while faucet aerators installed in a bathroom save 47.88 kWh per year.

The UCT and TRC ratios for the program are 0.14 and 0.28, respectively. The program's cost-effectiveness was impacted by the suspension of in-home visits due to COVID-19. In an effort to improve the accuracy of the data being collected, Idaho Power has modified the installation worksheets to be used in 2021. The company worked with installers to ensure the collection of the additional information would not be a burden to them when the direct installs resume. The updated installation worksheets will help Idaho Power calculate the lighting savings for each project based on information around the existing lamp and the location of the installation rather than using a deemed savings value from the RTF.

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 the 33 apartments. Both an online and mail-in option were offered but no surveys were returned in 2020.

2021 Program and Marketing Strategies

Idaho Power will resume pursuing energy-efficient direct-installation projects in multi-family dwellings throughout its service area when the program activities can be completed in a safe manner for both customers and contractors in consideration of COVID-19 protocols.

Once installations resume, Idaho Power will continue to use informative notifications, pre-installation door hangers, and post-installation informational marketing pieces, as well as survey cards for scheduled projects. The company will also advertise in industry publications to encourage property owner/manager engagement and increase program visibility.

Oregon Residential Weatherization

		2020	2019
Participation and Savings			
	Participants (audits/projects)	0	8
	Energy Savings (kWh)	0	2,069
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$5,313	$5,982
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$5,313	$5,982
Program Levelized Costs			
	Utility Levelized Cost ($/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 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 to 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%-interest loan for a portion of the costs for weatherization measures.

Program Activities

Due to COVID-19 restrictions, Idaho Power suspended in-home activity on March 16, 2020, and it remained suspended through the end of 2020, which resulted in a reduction in program participation.

In 2020, two customers returned a card from the program brochure indicating interest in the program. Because the company received these cards after in-home activity had been suspended, these audits were not performed. The energy advisor notified these customers of the suspension and let them know they would receive a call as soon as in-home activity was reinstated.

Marketing Activities

In October, Idaho Power sent its Oregon residential customers 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 Schedule 78 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.

2021 Program and Marketing Strategies

Once COVID-19 safety protocols allow in-home activity to resume, Idaho Power will market the program to customers with a bill insert/brochure.

Rebate Advantage

		2020	2019
Participation and Savings			
	Participants (participants)	116	109
	Energy Savings (kWh)	366,678	353,615
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$174,670	$148,220
	Oregon Energy Efficiency Rider	$4,897	$8,529
	Idaho Power Funds	$855	$0
	Total Program Costs—All Sources	$180,422	$156,748
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.031	$0.023
	Total Resource Levelized Cost ($/kWh)	$0.075	$0.052
Benefit/Cost Ratios*			
	Utility Benefit/Cost Ratio	1.69	1.82
	Total Resource Benefit/Cost Ratio	0.98	1.14

*2020 cost-effectiveness ratios include evaluation expenses. If evaluation expenses were removed from the program's cost-effectiveness, the UCT and TRC would be 1.73 and 0.99, respectively.

Description

Initiated in 2003, the Rebate Advantage program helps Idaho Power customers in Idaho and Oregon with the initial costs associated with purchasing new, energy-efficient, ENERGY STAR® qualified manufactured homes. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by the home. 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 educates manufactured home buyers and retailers about the benefits of owning energy-efficient models. The Northwest Energy-Efficient Manufactured Home Program™ (NEEM), a consortium of manufacturers and state energy offices in the Northwest, establishes quality control (QC) and energy efficiency specifications for qualified manufactured homes and tracks their production and on-site performance. NEEM adds the classification Eco-Rated ™ for homes that are produced by factories that have demonstrated a strong commitment to minimizing environmental impacts from the construction process.

In 2019, NEEM created the most stringent manufactured home energy standard in the country, the ENERGY STAR® with NEEM 2.0 specification, which was later renamed the ENERGY STAR® with NEEM+ certification. NEEM+ standards are engineered to save approximately 30% more energy than ENERGY STAR® standards. As a result, not only does NEEM+ deliver the highest possible energy savings, it delivers the highest level of overall comfort. These homes are built to specifications tailored to the Northwest climate.

Program Activities

In 2020, for each home sold, the residential customer incentive for this program was $1,000 and the sales staff incentive was $200. Idaho Power paid 116 incentives on new manufactured homes, which accounted for 366,678 annual kWh savings. This included 114 homes sited in Idaho and two sited in

Oregon. Of the 116 homes in the program, 32 were NEEM+, 79 were ENERGY STAR, and five were Eco-Rated.

Marketing Activities

Idaho Power continued to support manufactured home dealerships by providing them with updated program marketing collateral.

In April and December, Idaho Power promoted the Rebate Advantage program with a bill insert sent to 321,081 and 307,578 customers, respectively. The insert had information about the potential energy and cost savings and referred customers to the program website.

In October, the company garnered 15,056 impressions on social media with a Rebate Advantage program promotion.

Cost-Effectiveness

In 2020, Idaho Power used the same savings and assumptions source as were used in 2019. In May 2020, the RTF updated savings for new construction manufactured homes. First, RTF removed the savings designation for Eco-Rated™ certified homes. The Eco-Rated certification is a green home program that signifies the production facility the homes are produced in demonstrate a high commitment to managing the environmental impacts during the building process. However, the energy savings associated with these homes are the same as those built to ENERGY STAR standards; therefore, the RTF voted to combine the savings for Eco-Rated and ENERGY STAR manufactured homes. Secondly, the RTF removed the assumptions related to NEBs. The previous assumptions were based on the reduction of supplemental fuel use which they found no evidence of occurring. Finally, when other assumptions around heating system type, lighting, and other appliances were updated, the average annual savings per home declined by 10%. Idaho Power will begin using RTF workbook version 4.1 in 2021.

The UCT and TRC for the program is 1.69 and 0.98 respectively. If the amount incurred for the 2020 evaluation was removed from the program's cost-effectiveness, the UCT would be 1.73 while the TRC would be 0.99.

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

Evaluation

In 2020, Idaho Power contracted with ADM Associates, Inc. to conduct an impact evaluation of 2019 reported savings. The evaluation determined that Idaho Power applied savings correctly and documented project information accurately. The impact evaluation reviewed the program database and conducted a desk review of sampled projects.

The evaluator calculated a realization rate of 100% for the 2019 program year and made no recommendations for future program changes. See the complete impact evaluation report in *Supplement 2: Evaluation*.

2021 Program and Marketing Strategies

Idaho Power plans to explore the cost effectiveness of adding an incentive tier for the ENERGY STAR with NEEM+ certification homes to help promote the sales of these higher efficiency homes. In addition, NEEM will be exploring whether to end the Eco-Rated™ homes classification.

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 explore digital advertising to promote the program to potential manufactured home buyers.

Residential New Construction Pilot Program

	2020	2019
Participation and Savings		
Participants (participants)	248	322
Energy Savings (kWh)	649,522	774,597
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$471,542	$534,118
Oregon Energy Efficiency Rider	$0	$0
Idaho Power Funds	$1,962	$0
Total Program Costs—All Sources	$473,504	$534,118
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.044	$0.035
Total Resource Levelized Cost ($/kWh)	$0.081	$0.092
Benefit/Cost Ratios*		
Utility Benefit/Cost Ratio	1.54	1.58
Total Resource Benefit/Cost Ratio	1.20	0.83

* 2019 cost-effectiveness ratios include evaluation expenses. If evaluation expenses were removed from the program's cost-effectiveness, the UCT and TRC would be 1.66 and 0.85, respectively.

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, all-electric homes that use heat pump technology in Idaho Power's Idaho service area. These homes must meet strict requirements that make them 10%, 15%, or 20% 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

In the first quarter of 2020, Idaho Power instituted a three-tier incentive structure for the Residential New Construction Pilot Program. Prior to that program update, a flat incentive of $1,500 was paid to all homes that achieved 20% above code or higher. Homes approved for the program prior to December 31, 2019 were grandfathered under the previous incentive structure.

The new tiered incentives are:

- 10 to 14.99% above code: $1,200 incentive
- 15 to 19.99% above code: $1,500 incentive
- 20% or more above code: $2,000 incentive

Idaho Power updated the application form so customers could easily fill it out and submit it online.

In 2020, the company paid incentives for 248 newly constructed energy-efficient homes in Idaho, and the homes accounted for 649,522 kWh of energy savings.

Idaho Power also reviewed the following recommendations from the 2019 impact evaluation:

- *Review the tracking database regularly to ensure that all parameters have reasonable and accurate values*. Idaho Power reviewed the database regularly before the evaluation and will continue to do so.
- *Clarify on the application form that builders with multiple units may submit only one application*. Idaho Power did not adopt this recommendation in 2020. Although it is not specifically written on the application, the program raters instruct their builders to fill out one application form and then list multiple homes on a separate sheet. Idaho Power is not aware of any situation where a builder has been confused. However, the next time the application is updated, Idaho Power will make this small update.
- *Modify the name of the application form PDF on the program website from "termsConditions.pdf" to something more specific*. Idaho Power adopted this recommendation and updated the PDF name to be more specific: IdahoPowerResNewConstApplication.pdf.
- Clearly document the sources for the program's baseline energy standards. The evaluator made this recommendation because they had a hard time obtaining information on the baseline heating systems (capacities, efficiencies, etc.) from the REM/Rate modeling software or AXIS database. Idaho Power is not able to change this because the software is provided from a third party. Upon speaking with the third-party software provider, the evaluator was able to attain the information they needed for their evaluation.
- *If the pilot becomes a fully-fledged program, add to the program marketing plan document to make it a true program handbook*. Idaho Power will add a complete program marketing plan document to the program handbook.
- *Ensure all hyperlinks on marketing materials work*. Idaho Power adopted this recommendation and checked all hyperlinks to ensure they were actively connected to the Residential New Construction webpage.
- *Track the number of clicks for digital ads*. Idaho Power already performs this recommendation.
- *Add content to program website*. The company regularly updates website content to keep it current and will consider adding success stories.
- *Add a URL to the program brochure that links builders with specific contact information for the raters*. Idaho Power has the RESNET-certified HERS rater contact info on the webpage. The webpage URL is listed on the program brochure.

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 the company's service area in 2020. The company participated in the IBCA Winter Board Meeting, but due to COVID-19 restrictions, the company was unable to participate in the IBCA Fall Board Meeting, the Building Contractors Association of Southwestern Idaho (BCASWI) builder's expo, the Snake River Valley

Building Contractors Association (SRVBCA) builder's expo, and the BCASWI and SRVBCA scholarship golf tournaments as in past years.

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, the SRVBCA, and the Building Contractors Association of Southeast Idaho (BCASEI). A print ad appeared in the *Idaho Business Review's Residential Contractor's Special Edition* in June as well as the March issue of *Boise Lifestyle* and *Meridian Lifestyle* magazines that highlighted top home builders. A digital app ad and company listing was also included as part of the advertising package with the MVBA.

The company sent a bill insert to 309,554 Idaho customers in May to promote the program. The program brochure was updated to show the new tiered incentive rates.

Cost-Effectiveness

The savings for the 248 energy-modeled homes average 2,619 kWh per home depending on which efficiency upgrades were included to meet the tiered over code program requirement. This was an increase over the average energy-modeled savings of 2,389 kWh per home in 2019.

While savings are custom calculated for each of the 248 modeled homes, the incremental costs over a code-built home are difficult to determine. The RTF's single-family new construction workbook was used as a proxy for the incremental costs and NEBs.

The UCT and TRC ratios for the program are 1.54 and 1.20 respectively.

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

2021 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 BCASEI. A bill insert is planned for spring 2021. 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.

NEEA made the decision to stop sponsoring the regional utility performance path homes programs but will still maintain the regional AXIS database. Idaho Power will contract with Washington State University's Energy Program for the program file and field QAs beginning sometime in first quarter of 2021.

The 2020 Idaho Legislature adopted a more stringent energy code and, as a result, Idaho Residential Energy code will be moving up from the 2012 IECC with state specific amendments to the 2018 IECC with state-specific amendments in January of 2021.

Shade Tree Project

		2020	2019
Participation and Savings			
	Participants (trees)	0	2,063
	Energy Savings (kWh)*	52,662	35,727
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$27,652	$147,750
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$838	$0
	Total Program Costs—All Sources	$28,490	$147,750
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	$0.235
	Total Resource Levelized Cost ($/kWh)	n/a	$0.235
Benefit/Cost Ratios**			
	Utility Benefit/Cost Ratio	n/a	1.09
	Total Resource Benefit/Cost Ratio	n/a	1.16

* Incremental savings for trees planted between 2013–2016 not claimed in previous years.

** No trees distributed in 2021 due to COVID-19 restrictions. Cost-effectiveness ratios have not been calculated.

Description

Idaho Power's Shade Tree Project operates in a small geographic area each spring and fall, offering no-cost shade trees to Idaho 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, schools, and other non-profit organizations.

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 local experts. These local specialists include city arborists from participating municipalities, Idaho Power utility arborists, county master gardeners, and CSI 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.

According to the DOE, a well-placed shade tree can reduce energy used for summer cooling by 15% 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—provide Idaho Power with the information to facilitate a shade tree project.

Program Activities

Idaho Power's first 2020 Shade Tree Project event was scheduled for late April. Due to COVID-19 restrictions and to ensure the safety of customers, employees, and volunteers, the spring event was cancelled. Because the pandemic remained ongoing in the fall, Idaho Power also cancelled the event scheduled to occur in October. The company researched alternative options for holding the Shade Tree Project events but determined those options couldn't be carried out consistent with COVID-19 safety protocols, or would have incurred additional costs, making the program not cost-effective. Customers were notified of the cancellation through the Shade Tree Project voicemail and an alert that was placed on the Idaho Power Shade Tree Project home page.

Marketing Activities

Because both spring and fall Shade Tree Project offerings were cancelled, the company made every effort to notify customers of the change and to communicate tree-related information. Idaho Power added a cancellation alert to its program homepage. The company also published shade tree-related content on its social media channels and shared content from the company's partners who were still able to provide trees locally, including the City of Boise's City of Trees Challenge. In November 2020, a newsletter was sent to last season's program participants. Instead of promoting the Shade Tree Project in *Home Energy Reports*, the reports featured general tips for planting shade trees.

Cost-Effectiveness

Due to COVID-19, Idaho Power's Shade Tree project events were canceled for 2020. Since no trees were distributed, the cost-effectiveness for the program has not been calculated since there is no savings benefit associated with the costs incurred in 2020. However, Idaho Power will report 52,662 kWh of savings for trees planted between 2013 and 2016. Unlike traditional energy savings measures in which the annual savings remain flat throughout the measure life and only first year savings are reported, for trees, the savings grow as the tree grows. The 52,662 kWh represents the incremental claimable annual savings not claimed in previous years.

For the Shade Tree Project, Idaho Power utilizes the Arbor Day Foundation's software, which calculates energy savings and other non-energy impacts based on tree species and orientation/distance from the home. This tool, i-Tree software, estimates these benefits for years five, 10, 15, and 20 after the tree planting year. However, the savings from the tool assumes each tree is planted as planned and does not take into account survivorship of the trees. Idaho Power contracted with DNV GL to develop a model to calculate average values per tree using the tool data and determined a realization rate based on the survival rate. The calculator was used to determine the 52,662 kWh of incremental claimable savings for 2020.

2021 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2021, returning it to the Treasure Valley in the spring and the Magic Valley in the fall. To ensure the safety of customers and employees, the enrollment process will remain the same, but the trees will be shipped directly to customers' homes. Arbor Day will manage shipping in the spring and fall which will eliminate the need for customers to attend an event to collect their trees.

Idaho Power will continue to market the program through direct-mail, focusing on customers identified as living in newly constructed homes and those identified using the Urban Tree Canopy Assessment tool in the Treasure Valley. The program will be promoted in the April 2021 *Home Energy Report*. In addition, Idaho Power maintains a wait list of customers who were unable to enroll because previous offerings were full. Idaho Power will reach out to these customers through direct-mail or email for the 2021 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™

		2020	2019
Participation and Savings			
	Participants (products)	6,894	5,729
	Energy Savings (kWh)	148,404	271,452
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$93,865	$87,599
	Oregon Energy Efficiency Rider	$3,539	$2,900
	Idaho Power Funds	$1,737	$0
	Total Program Costs—All Sources	$99,141	$90,499
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.073	$0.032
	Total Resource Levelized Cost ($/kWh)	$0.073	$0.043
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.78	1.40
	Total Resource Benefit/Cost Ratio	3.24	5.56

Description

Initiated in 2015, the Simple Steps, Smart Savings™ program is designed to increase sales of qualified energy-efficient appliances by encouraging customers to purchase energy-efficient clothes washers by offering an incentive on select products at the point of purchase.

Idaho Power and other regional utilities participate in the program, which is managed by a third-party contractor. Idaho Power pays the contractor 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. The funding can also be used for retailer promotions.

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.

BPA's Simple Steps program ended on September 30, 2020. The Simple Steps program was a combination of lighting sales along with showerhead and appliances sales. The decision to end the program was made because the lighting market transformed to high-efficiency lightbulbs. With most of the Simple Steps sales coming from lighting products, the program could not be cost-effectively maintained by just showerhead and appliances sales.

Idaho Power continued participation in the Simple Steps program until September 30. Idaho Power also participated 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.

Program Activities

In the nine months the program was active, Idaho Power provided funding for qualified ENERGY STAR® rated clothes washers and high-efficiency showerheads. Idaho Power worked with Sears Hometown, RC Willey, and Best Buy to reduce the cost of select washers by $25. In 2020, customers purchased 392 units, compared to 761 in 2019. The decrease in participation was likely due to restrictions related to COVID-19 as stores temporarily closed or required appointments to look at products.

Idaho Power worked with six participating retailers on the high-efficiency showerhead promotion to reduce the price as follows: $5-$6 for 1.5 and 1.75 gpm units and $2 for 2.0 gpm units. Customers purchased 6,502 qualified showerheads, as compared to 4,968 in 2019. Of those sales, 12% were 1.50 gpm, 5% were 1.75 gpm, and 83% were 2.0 gpm showerheads.

Marketing Activities

To help support the appliance promotions, static clings were displayed on all qualifying units. These pieces informed customers about the promotion and the incentive they would receive. Monthly visits to check stock, point-of-purchase signs, and displays were suspended from March 26 until September 1, when field staff returned to stores to remove displays and remind store staff and management of the program end date.

Idaho Power posted information about the appliance promotions on its Appliances web page until September 30.

Cost-Effectiveness

In 2019, the RTF reviewed and updated the savings assumptions for showerheads. As with past RTF workbooks, Idaho Power adjusts the assumptions regarding electric water heating saturation from the regional average of 60% to the company's average of 49% from the 2016 residential end-use study. Previously, the annual savings for showerheads ranged between 15 to 63 kWh with the electric water heat saturation adjustment. Based on the new workbook, showerhead annual savings are now between 5 and 69 kWh. While overall showerhead sales increased by 31% between 2019 and 2020, savings for showerheads decreased by 51%. This is largely due to increase of sales of the 2.0 gpm showerhead which made up 47% of sales 2019 and 83% in 2020. The savings for this showerhead type fell by 63% which impacted the overall cost-effectiveness of the program. The parameters that impacted the savings for showerheads include assumptions regarding the market baseline, in-situ flow rates, and number of showers.

For clothes washers, 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 153 kWh per unit, Idaho Power applies the annual site savings of 142 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.

The UCT and TRC ratios for the program are 0.78 and 3.24, respectively. The cost-effectiveness was largely impacted by the decrease of per unit showerheads savings. The RTF reviewed the showerhead savings again in 2020 and decided to deactivate the measure due to the market transformation in the region. Due to this and the other changes impacting the lighting portion of the Simple Steps promotion, BPA decided to sunset the offering on September 30, 2020.

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

2021 Program and Marketing Strategies

Idaho Power is in the process of trying to find a vendor to offer a new program to provide incentives for select ENERGY STAR rated appliances. Because the RTF deactivated the showerhead workbook, Idaho Power is unable to claim savings and provide an incentive for the purchase of high-efficiency showerheads. As a result, Idaho Power will not be including showerheads in any buydown promotions.

Weatherization Assistance for Qualified Customers

		2020*	2019
Participation and Savings			
	Participants (homes/non-profits)	115	197
	Energy Savings (kWh)	218,611	649,299
	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	$1,385,577	$1,303,727
	Total Program Costs—All Sources*	$1,385,577	$1,303,727
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.244	$0.114
	Total Resource Levelized Cost ($/kWh)	$0.353	$0.171
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.20	0.35
	Total Resource Benefit/Cost Ratio	0.33	0.43

* 2020 Total Program Costs includes accounting accruals and reversals associated with unspent dollars carried over into the next year. These accruals and reversals have been removed from the cost-effectiveness and levelized cost calculations.

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 weatherization funds to serve more customers with special needs in electrically heated homes.

Idaho Power has an agreement with each CAP agency in its 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.

Annually, Idaho Power requires verification of approximately 10% 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 processes for weatherized homes. The state hires the quality-control inspector who ensures measures were installed to DOE and state WAP specifications. Utility representatives, weatherization personnel from the CAP agencies, CAPAI, and a Building Performance Institute (BPI) certified QC inspector review homes weatherized by each of the CAP agencies.

For the second method, Idaho Power contracts with two companies—Kent Kearns Enterprises and Greenback Home Solutions, LLC—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. Greenback Home Solutions verifies weatherization services provided through the WAQC program in the Capital and Canyon–West regions of Idaho. 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 as set forth below in compliance with IPUC Order No. 29505, as updated in Case No. IPC-E-16-30, Order No. 33702 and consolidates the WAQC Annual Report with Idaho Power's *Demand-Side Management Annual Report* each year.

Program Activities

Weatherized Homes and Non-Profit Buildings by County

In 2020, Idaho Power made $1,369,325 available to Idaho CAP agencies. Of the funds provided, $720,457 were paid to Idaho CAP agencies, while $648,868 were accrued for future funding. This larger carryover was caused by COVID-19 in-home activity restrictions limiting the number of homes CAP agencies weatherized. Of the funds paid in 2020, $654,961 directly funded audits, energy efficiency measures, and health and safety measures for qualified customers' homes (production costs) in Idaho, and $65,496 funded administration costs to Idaho CAP agencies for those homes weatherized.

In 2020, Idaho Power funds provided for the weatherization of 115 homes in Idaho, none in Oregon, and no non-profit buildings in Idaho. 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 2020

Agency/County	Number of Homes	Production Cost	Average Cost	Administration Payment to Agency	Total Payment
Idaho Homes					
EICAP					
Lemhi	0	$ 0	$ 0	$ 0	$ 0
Agency Total	**0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
EL ADA					
Ada	48	270,318	5,632	27,032	297,350
Elmore	8	54,716	6,839	5,472	60,187
Owyhee	11	63,107	5,737	6,311	69,417
Agency Total	**67**	**$ 388,141**	**$**	**$ 38,814**	**$ 426,955**
Metro Community Services					
Boise	1	6,504	6,504	650	7,155
Canyon	10	70,738	7,074	7,074	77,812
Gem	4	32,430	8,107	3,243	35,673
Payette	4	26,864	6,716	2,686	29,551

Agency/County	Number of Homes		Production Cost		Average Cost		Administration Payment to Agency		Total Payment
Washington	1		10,037		10,037		1,004		11,040
Agency Total	**20**	**$**	**146,573**	**$**		**$**	**14,657**	**$**	**161,230**
SCCAP									
Blaine	3		20,894		6,965		2,089		22,984
Cassia	1		4,929		4,929		493		5,422
Jerome	4		26,786		6,696		2,679		29,464
Lincoln	1		9,274		9,274		927		10,202
Twin Falls	6		28,067		4,678		2,807		30,874
Agency Total	**15**	**$**	**89,950**	**$**		**$**	**8,995**	**$**	**98,945**
SEICAA									
Bannock	7		19,489		2,784		1,949		21,438
Bingham	5		7,117		1,423		712		7,829
Power	1		3,690		3,690		369		4,059
Agency Total	13	**$**	**30,296**	**$**		**$**	**3,030**	**$**	**33,326**
Total Idaho Homes	115	**$**	**654,961**	**$**		**$**	**65,496**	**$**	**720,457**
Non-Profit Buildings									
Canyon	1		10,572		10,572		1,057		11,630
Lincoln	1		14,993		14,993		1,499		16,492
Payette	1		12,555		12,555		1,256		13,811
Twin Falls	1		13,924		13,924		1,392		15,316
Total Non-Profit Buildings	**0**	**$**	**0**	**$**	**0**	**$**	**0**	**$**	**0**
Oregon Homes									
CCNO									
Agency Total	**0**	**$**	**0**		**0**	**$**	**0**	**$**	**0**
CINA									
Agency Total	**0**	**$**	**0**	**$**	**0**	**$**	**0**	**$**	**0**
Total Oregon Homes	**0**	**$**	**0**	**$**	**0**	**$**	**0**	**$**	**0**
Total Program	**115**	**$**	**654,961**	**$**		**$**	**65,496**	**$**	**720,457**

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 each 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 in the 2020 agreement was $6,000. In 2020, Idaho CAP agencies had a combined average cost per home weatherized of $5,695.

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% of Idaho Power's per-job production costs. The average administration cost paid to agencies per Idaho home weatherized in 2020 was $570. Not included in this report's tables are additional Idaho Power staff labor, marketing, home verification, and support costs for the WAQC program totaling $50,028 for 2020. 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 2020, $156,791 in unspent funds from 2019 were made available for expenditures in Idaho. Table 13 details the funding base and available funds from 2019 and the total amount of 2020 spending.

Table 13. WAQC base funding and funds made available in 2020

Agency	2020 Base	Available Funds from 2019	Total 2020 Allotment	2020 Spending
Idaho				
EICAP	$ 12,788	$ 0	$ 12,788	$ 0
EL ADA	568,479	0	568,479	426,955
Metro Community Services	302,259	0	302,259	161,230
SCCAP	167,405	55,690	223,095	98,945
SEICAA	111,603	71,709	183,312	33,326
Non-profit buildings	50,000	29,391	79,391	0
Idaho Total	**$ 1,212,534**	**$ 156,791**	**$ 1,369,325**	**$ 720,457**

Note: Dollars are rounded.

To help keep weatherization crews and customers safe from exposure to COVID-19, CAP Agencies temporarily suspended weatherization activities for Idaho Power's WAQC program in March 2020. In 2020, neither CAP Agencies nor Idaho Power monitored weatherized homes and no visits were made to customer homes through the state monitoring system. Because only 10 homes were weatherized by March, Idaho Power did not have the opportunity to have any of the homes verified through its home verification system.

The DOE also had CAP Agency Weatherization adjust services and follow Centers for Disease Control (CDC) and DOE guidelines if individual agencies did not suspend services. Some CAP agencies began certain weatherization activities under CDC and DOE guidelines in early summer. Because weatherization personnel provided services for the state WAPs between March and December, Idaho Power allowed CAP agencies within its service area to leverage state and federal funding along with its funding.

Because COVID-19 restrictions caused various weatherization departments to lose months of work, production schedules were lower than normal, and more Idaho Power funding was not spent. Unspent funding will be carried over and used for weatherization services in 2021.

Weatherization Measures Installed

Table 14 details home counts for which Idaho Power paid all or a portion of each measure's cost during 2020. 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 WAPs 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, 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 (IAQ). Idaho Power contributes funding for the installation of items that do not save energy, such as smoke and carbon monoxide detectors, vapor barriers, 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 summary of measures installed in 2020

	Counts	Production Costs
Idaho Homes		
Audit	85	$ 9,129
Ceiling Insulation	39	38,046
CFLs/LED Bulbs	18	996
Doors	58	43,241
Ducts	16	9,483
Floor Insulation	23	29,528
Furnace Repair	2	549
Furnace Replacement	86	337,409
Health and Safety	21	15,410
Infiltration	79	8,628
Other	3	11,990
Pipes	5	346
Vents	5	222
Wall Insulation	5	2,128
Water Heater	1	1,348
Windows	73	146,509
Total Idaho Homes		**$ 654,961**
Oregon Homes	0	**$ 0**
Total Oregon Homes		**0**
Idaho Non-Profits	0	**0**
Total Idaho Non-Profit Measures		**$ 0**

Note: Dollars are rounded.

Marketing Activities

Information about WAQC is available in a brochure (English and Spanish) and on the Income Qualified Customers page of Idaho Power's website. The CAP agencies promote the program and maintain a continual waiting list for interested customers.

Cost-Effectiveness

Program cost-effectiveness declined in 2020 from both the UCT and TRC perspective due to the adoption of updated per home savings estimates informed by a third-party weatherization billing analysis. The UCT declined from 0.35 to 0.20, while the TRC decreased from 0.43 to 0.33.

To address the decrease in cost-effectiveness from lower energy savings estimates, Idaho Power will work with EEAG, as well as the weatherization managers who oversee the weatherization work, to discuss ways to improve the program. See the WAQC evaluation section for more details of the billing analysis.

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% of total production costs to Idaho Power. Using the audit tool to pre-screen projects ensures each weatherization project will result in energy savings.

The 2020 cost-effectiveness analysis continues to incorporate the following directives from IPUC Order No. 32788:

- Applying a 100% NTG value to reflect the likelihood that WAQC weatherization projects would not be initiated without the presence of a program
- Claiming 100% of project savings
- Including an allocated portion of the indirect overhead costs
- Applying the 10% 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

Finally, the cost-effectiveness calculations were updated in 2020 to remove the impacts of any accruals and reversals associated with unspent dollars carried over into the following year. Generally, the carryover dollars are reversed the following year when the CAP agencies spend the previous year's unused funds. A new accrual is made at the end of the year for the new carryover dollars. These annual accruals and reversal have been similar in amount each year and have had a relatively minimal impact on the total utility cost of the program and to the program's overall cost-effectiveness. As mentioned previously, because weatherization work was restricted during COVID-19, Idaho Power is carrying over a larger amount of dollars from 2020 to 2021. By leaving this accounting entry in the cost-effectiveness calculation, it would overstate expenses in 2020 while the subsequent reversal would understate expenses in 2021.

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 educational materials for distribution to customers during home visits. Any customers whose homes are selected for the company's post-weatherization home verification receive additional information and have the opportunity to ask the home verifiers more questions.

Idaho Power uses independent, third-party verification companies to ensure the stated measures were installed in the homes and to discuss the program with these customers. In 2020, home verifiers did not visit customer homes for feedback about the program due to COVID-19 concerns.

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 94 of 115 households weatherized by the program in 2020. Some highlights include the following:

- Nearly 39% of respondents learned of the program from a friend or relative, and over 21% learned of the program from an agency flyer.
- Almost 80% of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, almost 40% had concerns about their existing furnace, and nearly 31% wanted to improve the comfort of their home.
- Over 73% reported they learned how air leaks affect energy usage, and nearly 67% indicated they learned how insulation affects energy usage during the weatherization process.
- Nearly 53% of respondents said they learned how to use energy wisely. Most respondents (98%) reported they were likely to change habits to save energy, and almost 63% reported they have shared all the information about energy use with members of their household.
- Over 94% of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost all (99%) said they were very satisfied with the program.
- Over 70% of the respondents reported the habit they were most likely to change was washing full loads of clothes, and more than 61% said that turning off all the lights when not in use was a habit they were likely to adopt to save energy. Turning the thermostat up in the summer was reported by nearly 53% of the respondents, and turning the thermostat down in the winter was reported by more than 56% 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*.

Evaluations

In late 2019, Idaho Power contracted with Nexant to conduct a billing analysis of 2016-2018 weatherization jobs for both the WAQC and Weatherization Solutions for Eligible Customers programs. The analysis estimated the electric energy savings of the weatherization jobs by comparing whole-home energy usage of the participants, before and after the weatherization jobs, to a matched comparison group. The results of the analysis showed that savings from weatherization jobs are detectable, but savings are reduced relative to savings reported in previous years, especially in regard to heat pump installations. Weatherization jobs completed in 2019 were not calculated because the analysis requires a full year of post-weatherization billing data, which were unavailable at the time of the study.

For program reported savings, Nexant recommended using the calculated savings from only 2018 weatherization jobs, to use the most recent data. However, to avoid anomalous and unreliable results, Nexant recommended utilizing the 2016-2018 weatherization results where sample sizes are low. Idaho Power has calculated 2020 savings for these programs in the manner recommended by Nexant.

Any changes to the program as a result of the billing analysis will be reported in the *Demand-Side Management 2021 Annual Report*. See the complete analysis report in *Supplement 2: Evaluation*.

2021 Program and Marketing Strategies

In 2021, Idaho Power will continue to provide financial assistance to CAP agencies while exploring changes to improve program delivery. The company will also continue to provide the most benefit possible to special-needs customers while working with Idaho and Oregon WAP personnel.

Idaho Power plans to verify approximately 10% of the homes weatherized under the WAQC program via home-verification companies and the Idaho and Oregon state monitoring process.

In 2021, 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 2021, Idaho Power expects to contribute the base amount plus available funds from 2020 to total $1,861,402 in weatherization measures and agency administration fees. Of this amount, $129,391 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 content on its website and other marketing collateral.

Weatherization Solutions for Eligible Customers

	2020	2019
Participation and Savings		
Participants (homes)	27	129
Energy Savings (kWh)	47,360	504,988
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$198,226	$936,721
Oregon Energy Efficiency Rider	$0	$0
Idaho Power Funds	$10,489	$20,905
Total Program Costs—All Sources	$208,715	$957,626
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.338	$0.119
Total Resource Levelized Cost ($/kWh)	$0.338	$0.119
Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	0.13	0.30
Total Resource Benefit/Cost Ratio	0.23	0.43

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% and 250% 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 IAQ, and/or provide health and safety measures 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% 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 2020, contractors weatherized 27 Idaho homes for the program: 10 in eastern Idaho, seven in Idaho Power's Canyon–West Region, four in south-central Idaho, and six in the company's Capital Region. Of those 27 homes weatherized, 15 were single-family, 11 were manufactured homes, and one was a multi-family unit.

Due to COVID-19 restrictions, in March 2020, the program suspended in-home activities. To help ensure crew members and customer safety, contractors did not enter customer homes throughout the rest of 2020.

Marketing Activities

Prior to the program suspending in-home activities in March, Idaho Power distributed one marketing email for weatherization and one bill insert in February. The email was sent to 3,010 customers and received 518 unique opens. The bill insert was sent to 297,471 residential customers in Idaho. The program was also promoted on the Idaho Power website homepage in January.

In the absence of Weatherization Solutions offerings, Idaho Power promoted do-it-yourself weatherization techniques in a social media post on National Weatherization Day and with a December bill insert. The insert was sent to 297,297 Idaho and Oregon residential customers and included tips like checking for air leaks, installing a smart thermostat, and behavior changes to increase comfort and lower energy bills.

Figure 17. Social media posts for Weatherization Solutions for Eligible Customers program

Cost-Effectiveness

Program cost-effectiveness declined in 2020 from both the UCT and TRC perspective due to the adoption of updated per home savings estimates as a result of a completed weatherization billing analysis. The 2020 UCT ratio is 0.13, down from 0.30, and the TRC ratio is 0.23 compared with 0.43 in 2019. See the WAQC evaluation section of this report for more details on the billing analysis.

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 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.

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
- The likelihood of household members changing behaviors to use energy wisely

Idaho Power received survey results from 11 of 27 households weatherized by the program in 2020. Some highlights include the following:

- Eighteen percent of respondents learned of the program from a friend or relative, and another almost 18% learned of the program from an agency flyer. Even though Idaho Power did not send any direct-mail letters about the Weatherization Solutions program in 2020, over 54% of respondents said they learned about the program from direct-mail. These respondents may be recalling a letter they received in a previous year.
- Nearly 82% of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, 27% wanted to improve the comfort of their home, and 27% had concerns about their existing furnace.
- Almost 73% reported they learned how air leaks affect energy usage, and over 45% indicated they learned how insulation affects energy usage.
- More than 55% of respondents said they learned how to use energy wisely. Eighty percent reported they were very likely to change habits to save energy, and almost 73% reported they have shared all the information about energy use with members of their household.
- Nearly 82% of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and 100% said they were very satisfied with the program.
- Eighty percent of the respondents reported the habit they were most likely to change was turning off lights when not in use, and 70% 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 70% of the respondents and turning the thermostat down in the winter was reported by 70% 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*.

Though two independent companies normally perform random verifications of weatherized homes and visit with customers about the program, in 2020, no homes were verified because of COVID-19 restrictions.

Evaluations

In 2020, Idaho Power contracted with Nexant to conduct a participant billing analysis of weatherization jobs completed in 2016-2018. The 2020 savings reported for the program are based on the recommendations and estimated savings from the Nexant evaluation. See the WAQC section of this report for more details.

Any program updates based on this analysis will be reported in the *Demand-Side Management 2021 Annual Report*. See the complete analysis report in *Supplement 2: Evaluation*.

2021 Program and Marketing Strategies

Once COVID-19 safety protocols allow for in-home work to resume, Idaho Power will notify contractors to resume weatherization projects.

Idaho Power may evaluate program guidelines in 2021, and potentially update the current audit software to a newer version. Once program activities resume, Idaho Power will update brochures as necessary to help spread the word about the program in all communities. Additional marketing for the program may include bill inserts, emails, *News Briefs*, website updates, and advertisements in various regional publications, particularly those with a senior and/or low-income focus. Social media posts and boosts, coordinated partner content, and employee education may be used to increase awareness. Regional marketing and targeted digital ads will be considered based on need as evidenced by any regional contractor’s waiting list for Weatherization Solutions services. The program will be promoted at county fairs, home shows, and resource fairs, as needed.

Commercial/Industrial Sector Overview

In 2020, Idaho Power's commercial sector consisted of 74,410 commercial, governmental, school, and small business customers. The number of customers increased by 1,555 or 2.1% from 2019. Energy use per month for customers in this sector is not as homogenous as other customer sectors and can vary by several hundred thousand kWh each month depending on customer type. In 2020, the commercial sector represented 27.1% of Idaho Power's total retail annual electricity sales.

Industrial and special contract customers are Idaho Power's largest individual energy consumers. In 2020, there were 127 customers in this category, which represented approximately 22.8% of Idaho Power's total retail annual electricity sales.

Idaho Power's C&I sector has many energy efficiency programs available to commercial, industrial, governmental, schools, and small business customers. The suite of options can help businesses of all sizes implement energy efficiency measures.

Table 15. Commercial/Industrial sector program summary, 2020

		Total Cost		Savings	
Program	**Participants**	**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response					
Flex Peak Program	141 sites	$ 542,480	$ 542,480		24
Total		**$ 542,480**	**$ 542,480**		**24**
Energy Efficiency					
C&IEE					
Custom Projects	169 projects	18,059,396	41,604,451	94,006,717	
Green Motors—Industrial	10 motor rewinds			56,012	
New Construction	119 projects	2,383,983	4,175,611	14,565,936	
Retrofits	630 projects	3,587,277	11,964,431	20,965,215	
Commercial Energy-Saving Kit	1,379 kits	103,678	103,678	258,368	
Small Business Direct Install	139 projects	339,830	339,830	780,260	
Total		**$24,474,163**	**$ 58,188,001**	**130,632,507**	

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

Energy Efficiency Programs

C&I Energy Efficiency—Custom Projects

For projects not covered by the New Construction or Retrofits options, Custom Projects offers incentives for qualifying large, custom energy efficiency projects and energy management measures, such as strategic energy management, tune-ups, system optimization, and recommissioning.

Additionally, Idaho business customers who wish to find ways to save energy and to quantify their savings can obtain a scoping assessment and detailed assessment through this option.

C&I Energy Efficiency—New Construction

This option offers specific incentives for designing and building better-than-code energy-efficient features into a new construction, major renovation, addition, expansion or change-of-space project.

C&I Energy Efficiency—Retrofits

This option offers specific incentives for simple energy-saving retrofits to existing equipment or facilities.

Green Motors Initiative

Under the Green Motors Initiative (GMI), service center personnel are trained and certified to repair and rewind motors 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% of the cost of a new motor.

Commercial Energy-Saving Kits

This program offers free ESKs filled with products and tips to help small businesses save energy. Three industry-specific versions of the kit are delivered directly to Idaho Power's small business customers: office, restaurant, and retail.

Small Business Direct Install

Idaho Power launched a SBDI program in November 2019 targeting typically hard-to-reach small business customers. SBDI is implemented by a third-party contractor that provides turn-key services. Idaho Power pays 100% of the cost to install eligible measures for customers who use 25,000 kWh annually or less. SBDI is offered to eligible customers in a strategic geo-targeted approach.

Oregon Commercial Audits

This statutory-required program offers free energy audits, evaluations, and educational products to Oregon customers to help them achieve energy savings.

Demand Response Program

Flex Peak

Idaho Power pays an incentive to commercial and industrial customers who participate in this demand response program. These customers voluntarily help the company reduce summer demand on specific summer weekdays or for other system needs.

Marketing

In 2020, Idaho Power continued to market the programs listed above, targeting the following customers: commercial, industrial, governmental, schools, small businesses, architects, engineers, and other design professionals.

Bill Inserts and Print Materials

A bill insert highlighting how Idaho Power's incentives can save customers money was included in 41,313 business customer bills in March and 41,275 bills in July.

Additionally, the company redesigned its C&I Energy Efficiency overview brochure in January.

Print and Digital Advertising

In 2020, Idaho Power had planned to expand on the new ad campaign for the C&I Energy Efficiency Program launched in 2019. The ads targeted small to large businesses and showed that saving energy and money is for everyone by highlighting program participants. However, due to COVID-19 safety concerns around the logistics of maintaining appropriate social distancing while photographing the campaign, the company did not expand its campaign in 2020. Given that the campaign was not expanded, the company opted not to advertise in new print and digital publications as originally intended.

The company continued using ads highlighting energy efficiency, along with the company's clean energy and low-price messaging in select publications.

Print ads ran in the *Idaho Business Review* in April, May, August, September, October, and November; the *BOC Bulletin* in January and August; and the *Idaho Association of General Contractors Building Idaho* magazine in the spring. Ads also ran in the Building Owners and Managers Association (BOMA) membership directory and symposium 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.

Idaho Power continued using search engine marketing to display Idaho Power's C&I Energy Efficiency Program near the top of the search results with the paid search terms when customers search for energy efficiency business terms. These ads received 183,107 impressions and 9,488 clicks.

Newsletters

Idaho Power produces and distributes *Energy@Work*, a newsletter about Idaho Power company information and energy efficiency topics for business customers. Typically, a printed version is produced twice a year, while an email version is produced quarterly. Two issues of the email version included content that aligns with the printed version, and the other two issues included more technical content.

Idaho Power had planned to send its first issue of *Energy@Work* in a print and electronic format in March 2020. The newsletter was about to go to print when COVID-19 became a serious concern, so the company pivoted its plans. The original newsletter content was replaced with articles highlighting free and low-cost tips for businesses that were running in a different capacity than normal, along with information on virtual training opportunities. Given that many people were now working from home, the company opted not to print the newsletter, but did send it electronically to 9,808 business customers in April.

The summer version of the newsletter was emailed to 12,315 customers in July. Topics included air circulation in buildings, a video about energy-saving improvements at the Idaho Humane Society, and descriptions of the free resources available to help customers save energy and money, such as IDL's ERL, tips brochures, and training opportunities. The fall issue, sent to 10,456 customers, focused on temporary incentive increases, Idaho Power's low prices, and a video about the proposed Boardman to Hemingway transmission line project. The winter issue was emailed to 13,085 customers in December. The newsletter highlighted the free energy efficiency services offered by the IDL, the recent closure of the Boardman Oregon coal plant, tips and incentives for reducing water leaks, and changes to net metering services.

Airport Advertising

To reach business customers, Idaho Power continued to display two backlit ads throughout the airport in 2020. An ad featuring program participants was located in the baggage claim area, while an ad on alternating airport display boards highlighted the company's clean energy goal—Clean Today. Cleaner Tomorrow.®—and the role energy efficiency plays in achieving that goal.

Radio

Idaho Power sponsored messages on public radio stations in Boise, Twin Falls, and Pocatello from July through September. The company ran a total of 370 messages in Boise and Twin Falls, and 549 messages in Pocatello.

Social Media

Idaho Power continued using regular LinkedIn posts focused on energy-saving tips, program details, incentives, and training opportunities. In April, the company ran a short series of energy-saving tips for businesses, specific to free and low-cost actions they could take during the pandemic. When appropriate, these messages were also shared on Idaho Power's Facebook and Twitter pages. The company also boosted Facebook posts related to some of the PR success story videos listed below.

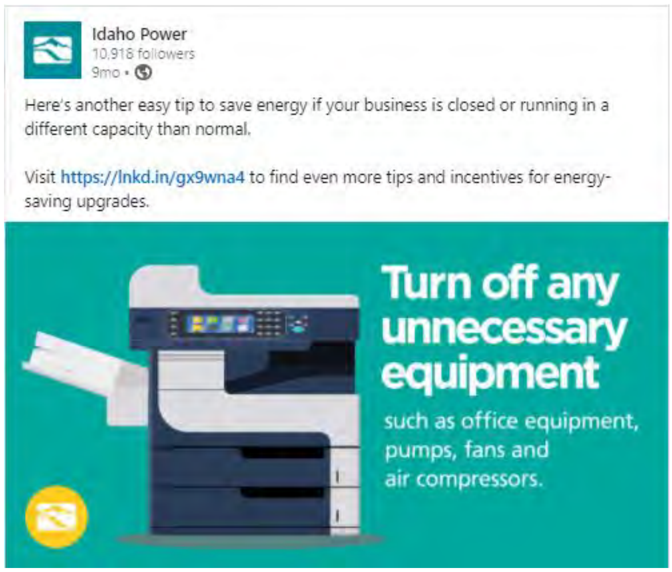

Figure 18. Energy-saving tip posted on LinkedIn

Public Relations

Idaho Power provides PR 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 used for media events and/or board meetings. Idaho Power will continue to assist customers with PR opportunities by creating certificates for display within their buildings and speaking at press events, if requested.

While these opportunities were limited in 2020, Idaho Power did produce checks and/or sent news releases for several companies, including Healthwise, the City of Blackfoot, the Idaho Humane Society, McCain Foods, and Amalgamated Sugar.

The company also released success story videos on YouTube highlighting how the Sun Valley Resort and Idaho Humane Society benefitted from Idaho Power's energy efficiency programs. The videos were shared on Idaho Power's social media channels, boosted on Facebook and promoted via a *News Briefs* article to media. The Idaho Humane Society video was also shared in the *Connections* newsletter and *Energy@Work* newsletter.

Association and Event Sponsorships

Idaho Power's C&I Energy Efficiency Program typically sponsors a number of associations and events. In 2020, many of these events were cancelled or held virtually.

The company sponsored the BOMA Commercial Real Estate Symposium February 11, in Boise. The Idaho Power Business Innovation and Development director participated in a panel discussion about growth in Idaho. The company also developed slides with key company facts that rotated on the screen before the event, hosted a booth with energy efficiency materials, and placed an energy efficiency flyer on each table setting.

Idaho Power also remained a sponsor of the *Idaho Business Review's* Top Projects Awards held virtually in August. The company logo was used throughout the event and a video featuring an Idaho Power senior engineer congratulated the winners and promoted and thanked them for using the company's energy efficiency programs.

Figure 19. Ad for the *Idaho Business Review* Top Projects Award

Customer Satisfaction

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2020, 57% 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-three percent of 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 2020 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 23% of the 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, 89% are "very" or "somewhat" satisfied with the program.

In 2020, 62% 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 percent of large commercial and industrial respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Sixty percent of customers surveyed in 2020 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 75% of the 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, 97% are "very" or "somewhat" satisfied with the program.

Based on surveys conducted in 2020, 61% of the business respondents in *the J.D. Power and Associates 2020 Electric Utility Business Customer Satisfaction Study* indicated they were aware of Idaho Power's energy efficiency programs, and on an overall basis, those customers were slightly more satisfied with Idaho Power than customers who are unaware of the programs.

Training and Education

In 2020, 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 program satisfaction. To market this service and distribute the training schedule and resources, Idaho Power used its website and *Energy@Work* newsletter.

In 2020, the company also began using a more unified approach to send emails informing customers of training opportunities. In place of asking each key account energy advisor to send the training announcements to their customers, the marketing specialist sent the training emails. The emails still appeared as if they were coming from the individual energy advisor but were sent from a central location. This resulted in emails that were more consistent looking and made tracking data on who received and opened the emails easier.

During each training session, the large commercial and industrial technical consultant gave an overview of the commercial and industrial programs available to customers.

As part of this outreach activity, Idaho Power collaborated with and supported stakeholders and organizations such as: IDL, BOMA, US Green Building Council (USGBC), and the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE). 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 BSUG, conducting Lunch & Learn sessions held at various design and engineering firms, and offering the ERL.

Idaho Power delivered five equivalent full-time days of technical classroom-based, live, online training sessions in 2020 at no cost to the customers over the course of 12 days. Topics included the following:

- Air Handling System Efficiency
- Energy Efficiency of Chilled Water Systems
- Owning & Operating an Efficient Cooling Tower
- Evaporative Cooling for Commercial & Industrial Facilities
- Fundamentals of Compressed Air Systems

The level of participation in 2020 remained high, with 236 individuals signing up for the class and 179 unique logins to the technical sessions. Due to the virtual nature of the course delivery due to COVID-19, in some cases there were multiple attendees at a single login location. Customer feedback indicated the average satisfaction level was 87%. Idaho Power's average cost to deliver the technical trainings in 2020 was approximately $2,800 per class, about half the cost of in-person delivered classes in 2019.

Field Staff Activities

Idaho Power energy advisors were able to meet on site with customers for the first two and a half months in 2020. Due to COVID-19 restrictions, energy advisors stayed in contact with their customers later in the year via phone call, email, text, Skype, and WebEx. Idaho Power used a variety of Idaho Power-developed programs, tools, and services to help customers with their energy-related questions and challenges. The company set activity goals for its energy advisors designed to engage customers in the energy efficiency programs such as a specific number of site visits, virtual customer contacts, or projects. Additionally, program specialists and engineers worked closely with field energy advisors to leverage established customer relationships. For example, residential and commercial energy advisors distributed informational materials to trade allies and other market participants who, in turn, supported and promoted 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

		2020	2019
Participation and Savings*			
	Participants (projects/kits)	928	1,470
	Energy Savings (kWh)**	129,593,880	133,865,895
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source***			
	Idaho Energy Efficiency Rider	$23,293,492	$21,111,360
	Oregon Energy Efficiency Rider	$661,370	$545,544
	Idaho Power Funds	$75,793	$52,501
	Total Program Costs—All Sources	$24,030,655	$21,709,405
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.018	$0.013
	Total Resource Levelized Cost ($/kWh)	$0.044	$0.030
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.27	3.56
	Total Resource Benefit/Cost Ratio	1.63	2.00

*Metrics for each option (New Construction, Custom Projects, and Retrofits) are reported separately in the appendices and in *Supplement 1: Cost-Effectiveness*.

**2019 total includes 117,223 kWh of energy savings from 12 Green Motors projects. 2020 total includes 56,012 kWh of energy savings from 10 Green Motors projects.

***2019 and 2020 dollars include totals for New Construction, Custom Projects, and Retrofits.

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.

Custom Projects

The Custom Projects option provides incentives for energy efficiency modifications to 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 also offers energy assessment 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 identified by the customer, Idaho Power, or 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. All lighting projects use the Idaho Power Lighting Tool to calculate the annual energy savings and to determine the incentive.

Once the project is completed, customers submit a payment application; in some cases, large, complex projects may take as long as two years or more to complete. 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 this verification process, the 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 project scope take place, 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 incorporate energy-efficient design features and technologies to new construction, expansion, or major remodeling projects. New construction and major renovation project design and construction process is much longer than small retrofits and often encompasses multiple calendar years. Originated in 2004, the option currently offers a menu of 33 measures and incentives for efficient lighting and controls, cooling, ventilation, building shell, controls, appliances, refrigeration, office equipment, and compressed air projects. The customer may otherwise lose savings opportunities for these types of projects.

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*.

Program Activities

Idaho Power has found providing facility energy assessments, customer technical training, and education services are key to encouraging customers to consider energy efficiency modifications. The 2020 activities not already described in the Commercial and Industrial Sector Overview are below.

Custom Projects

Incentive levels for the non-lighting projects remained the same in 2020, at 18 cents per kWh of first year savings, up to 70% of the project cost. In 2020, the company added a new energy management incentive of $0.025/kWh saved up to 100% of the eligible costs.

The energy management incentive was added for a variety of reasons. Compared to capital investment projects related to energy efficiency, energy management projects:

- tend to have a shorter measure life and a much lower cost.
- involve O&M changes that save energy without interrupting the customer's service or product.
- generate cost-effective energy savings from measures rooted in low-cost or no-cost O&M improvements.

Idaho Power designed a new custom offering in 2020 for conducting leak assessments and fixing underground water leaks, which covers $1,000 per five miles of pipe for a third-party leak assessment and offers a custom incentive of $0.18/kWh saved up to 70% of the eligible cost to repair the leaks found with a leak assessment for eligible underground pipes.

Idaho Power funds the cost of engineering services, up to $4,500, for conducting energy scoping assessments to encourage its larger customers to adopt energy efficiency improvements. Idaho Power contracted with five firms to provide scoping assessments and general energy efficiency engineering support services.

The Custom Projects option had a successful year with a total of 169 completed projects, 22 of which were in Oregon. Custom Projects achieved energy savings of 94,007 MWh (Table 16). Energy savings increased in 2020 by 33% over 2019. Idaho Power also received 95 new applications representing a potential of 19,310 MWh of savings on future projects.

Table 16. Custom Projects annual energy savings by primary option measure, 2020

Option Summary by Measure	Number of Projects	kWh Saved
Compressed Air	9	1,083,535
Controls	5	641,988
Energy Management	11	2,202,821
Fans	3	876,224
HVAC	4	1,471,836
Lighting	89	12,566,042
Motors	1	1,895,391
Other	2	9,068,218
Pump	12	1,815,041
Refrigeration	18	30,168,378
VFD	15	32,217,243
Total*	**169**	**94,006,717**

*Does not include Green Motor Initiative project counts and savings.

Custom Projects engineers and the key account energy advisors 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. These started as face-to-face interactions, though virtual/remote capabilities were developed and implemented when health or safety restrictions were necessary. Idaho Power also provided sponsorship for the 2020 Idaho Rural Water Conference (in person) and the 2020 ASHRAE Technical Conference (virtual). Custom Projects engineers gave presentations on Idaho Power programs and offerings at the Cohort for Schools Mid-term and Final Workshops (virtual), Water Cohort Workshops (in person and virtual), and the Eastern Oregon Operators Conference (virtual).

In 2020, Idaho Power contractors completed 11 scoping assessments on behalf of Idaho Power customers. These assessments identified over 6,000 MWh of savings potential and will be used to promote future projects.

Cohorts and Offerings

The Municipal Water Supply Optimization Cohort (MWSOC), Wastewater Energy Efficiency Cohort (WWEEC), the Eastern Idaho Water Cohort (EIWC) and Continuous Energy Improvement (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. Capital projects promoted or identified in strategic energy management offerings are reported and incentivized through other Idaho Power C&I programs, not as a cohort savings number. Each offering is described below.

Municipal Water Supply Optimization Cohort

The MWSOC began 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 that produce long-term energy and cost savings.

Third-year incentives and savings totaled $7,484 and 806,401 kWh /year with all incentives paid at 70% of the eligible cost. Third-year incentives were processed, and savings were reported in 2020.

Idaho Power continued the cohort for 11 of the original 15 participants and offered two continuation workshops in 2020. Idaho Power's contractor minimally contacted participants to check on project progress and opportunities and to address energy model data updates. Custom Projects engineers conducted multiple informational meetings for civil engineers (in person and virtual) who specialize in water and wastewater designs to educate them on the C&I Energy Efficiency Program, the assessment process, energy efficiency opportunities, and available tools and resources to help find energy efficiency projects.

Wastewater Energy Efficiency Cohort

In January 2014, Custom Projects launched WWEEC, a two-year cohort training approach and incentives for low- or no-cost energy improvements for 11 municipal wastewater facilities in Idaho Power's service area. In 2016, Idaho Power decided to extend the WWEEC to further engage customers. Seven of the 11 original participants are engaged in the WWEEC Continuation with many of the original participants starting major construction projects in years two and three of WWEEC.

Fifth-year incentives and savings were processed and reported in 2020, totaling $1.904 and 701,335 kWh/yr with incentives capped at 70%. In the fifth year, the consultant contacted participants to check on progress, discuss opportunities, and to address energy model data updates.

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. The third program year of the Cohort for Schools ran from June 2019 through March 2020. Five school districts of the original nine continued to implement CEI concepts and planned activities for the cohort. In October of 2019, five new school districts began participating. These districts developed their energy teams, built initial facility energy models, and went through training on various aspects of CEI and energy efficiency.

Energy savings for the original five participants were evaluated from June 2019 through March 2020 and from October 2019 through March 2020 for the five new participants. Activities were planned through May 2020 to complete a full 12-month cycle for the original five participants, however, COVID-19 restrictions caused anomalous operations starting around April 2020 and program year three was therefore concluded. The cohort is implemented by a third-party consultant that provided final savings reports for third-party energy savings, but due to the timing of receiving the report, these savings will be claimed in 2021.

Third-year activities commenced in fall 2019, concluding at the end of March 2020. Three of the five new school districts withdrew from the cohort at the end of program year three due to challenges associated with COVID-19. The remaining seven continued through 2020. Of those seven, five districts are now modeling all schools in their district. One district added four new facilities to the cohort, one added two new facilities, and another added one new facility in program year three.

Activities in 2020 included managing a register of energy efficiency opportunities for each facility detailing low-cost and no-cost opportunities to reduce energy consumption. The consultant worked with each participant to complete as many identified opportunities as possible. Afterward, the consultant checked in monthly by phone to review opportunity register items and to discuss current activities. Additionally, Idaho Power completed scoping assessments for each new facility to identify capital project opportunities to aid the strategic capital planning process. Idaho Power provided program and incentive information, both in hard copy and electronically, along with many other energy-saving resources pertinent to school facilities.

A virtual mid-term workshop was held January 14, 2021, where school districts reported their results through the end of 2020.

Fourth-year activities will continue until May 31, 2021. Idaho Power will then review final M&V reports to establish energy savings and eligible costs for the fourth-year activities and will distribute the corresponding incentives to participating school districts.

Streamlined Custom Efficiency

Started in 2013, the SCE offering continues to keep vendor engagement high, targeting projects that may have typically been too small to participate in the Custom Projects option. Currently, the SCE offering provides custom incentives for refrigeration controllers for walk in coolers, process-related variable frequency drives (VFD), and other small, vendor-based projects that do not qualify for prescriptive incentives.

Idaho Power contracted with a third party to manage SCE data collection and analysis for each project. In 2020, the SCE offering processed 20 projects totaling 3,490,011 kWh of savings and $523,242 in incentives.

Eastern Idaho Water Cohort

The Eastern Idaho Water Cohort began in January 2018 with the goal to offer the MWOSC to the eastern part of Idaho Power's 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. Second-year incentives were processed, and savings were reported in 2020 totaling $8,990 and 695,084 kWh/yr. In the second year of the offering, Idaho Power's contractor contacted participants to check on project progress and opportunities and to address energy model data updates. Idaho Power authorized a continuation for both customers and a draft of the third-year energy savings report is expected in 2021.

Green Motors Initiative

Idaho Power participates in the Green Motors Practices Group's (GMPG) 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% of the cost of a new motor. The GMI is available to Idaho Power's agricultural, commercial, and industrial customers.

Currently, nine motor service centers have signed on as GMPG members in Idaho Power's service area. Under the initiative, Idaho Power pays service centers $2 per horsepower (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 the customer 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 QA.

In 2020, a total of 10 C&I customers' motors were rewound, and the savings for the Green Rewinds is 56,012 kWh.

New Construction

In 2020, 119 projects were completed, resulting in 14,565,936 kWh in energy savings in Idaho and Oregon. New Construction had a 29% reduction in total projects and a 29% reduction in total savings compared to 2019.

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. The company began an internal review of the New Construction measures in 2020 and will update the program offerings in 2021. The TRM has been updated to include 2018 IECC information and will be finalized in 2021.

In addition to the customer incentive, a PAI is available to architects and/or engineers for supporting technical aspects and documentation of a project. On September 23, 2020, Idaho Power increased the eligible PAI incentive from 10% to 20% of the participant's total incentive, and correspondingly increased the PAI maximum from $2,500 to $5,000 per application.

The company believes the increase in PAI will increase engagement with architects and engineers and will be most beneficial to small and medium businesses as they prepare project documentation. These customers typically do not have staff with a technical background in construction which makes completing applications and submitting documentation a challenge. The previous PAI may not have been at a competitive rate for an architect or engineer to allocate his/her time to provide required program documentation for small energy savings projects. The company will study the impacts on customer participation and satisfaction with the increased PAI approximately one year after implementation. This timeframe provides sufficient lead time to promote the incentive increase for new construction projects. In 2020, 40 projects received the PAI compared to 65 projects in 2019. Idaho Power representatives did not make in-person visits to architectural and engineering firms in Boise in 2020 due to COVID-19 restrictions, but continued discussions via phone and email. These conversations are intended 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 post-project verifications on 10% of projects completed in 2020. The University of Idaho's IDL did not complete on-site post-project verifications in 2020, but rather completed desk reviews of all documentation on 13 of the 119 projects—over 10% of the total completed. The purpose of the verifications is to confirm program guidelines and requirements are adequate to ensure the supporting final project documentation provided aligns with field installation. Only minor discrepancies were identified in verified projects in 2020. See *Supplement 2: Evaluation* for the complete IDL report.

The impact evaluation from 2019 had a recommendation to: "Utilize [Hours of Use] HOUs from the TRM for lighting and HVAC projects started after the TRM was implemented," and "Also, the sources for the TRMs data are clearly cited and can be traced back to original research." Idaho Power program staff will address this by including additional transparency and clarification in the new 2021 TRM and an updated hours of operation table for HVAC and lighting.

Retrofits

The Retrofits option achieved 20,965 MWh of energy savings in 2020, representing 630 projects. Once again, lighting retrofits comprised most of the energy savings and projects.

At the beginning of 2020, Idaho Power assessed ways to optimize local contractor and supplier participation in Retrofits and determined to convene a small focus group of contractors and suppliers to discuss their program participation experience. Idaho Power program staff also brainstormed ideas that might be helpful to optimize contractor/supplier involvement.

Because contractors and suppliers were focused on their businesses and the new safety and health protocols related to the pandemic, the focus group idea was not viable. Instead, Retrofits program staff chose to implement two tactics to help enhance program participant experience. One tactic was to increase outreach to participating contractors and suppliers. Though contractor outreach and the offer of support is something program staff regularly does, during the pandemic, it became even more important to increase the frequency via phone, and text to let contractors and suppliers know the Retrofits incentives remained in place and program support was available.

Idaho Power asked a few regional utilities in 2020 how they were addressing the decline in program participation and found that some were offering increased incentives for a limited time. Contractors have choices on what projects they undertake and increasing lighting incentives provided the reason some needed to put their time toward lighting retrofit projects.

In August 2020, Idaho Power rolled out its second tactic to help enhance program participation: a temporary incentive increase for Idaho customers. The timing proved to be effective, as electrical contractors had, for the most part, resumed normal operations (compared to the early months of the pandemic). The company promoted the increased incentives via email and phone calls.

Within a few weeks, participating contractors shared that the increased incentives were having the desired effect. The initial timeline was to end the increased incentives in December 2020; however, electrical suppliers experienced difficulty receiving ordered equipment due to the worldwide impacts of the pandemic. In addition, Retrofits staff proposed to continue the increased incentives as part of the regular program offering and began preparations to roll out more comprehensive lighting incentive changes in the first quarter of 2021.

The COVID-19 pandemic had an impact on performing site inspections, visiting trade allies in-person, and holding in-person workshops in 2020. Lighting and non-lighting inspectors performed virtual project inspections from mid-March to early October. Most customers were able to accommodate the virtual inspections. The few projects where virtual inspections were not possible were inspected when site visits resumed in October.

The non-lighting Retrofits savings and cost are determined by Idaho Power's TRM. In 2020, the company contracted with a third party to update its TRM; program staff will review the update and propose changes to the non-lighting measures in 2021.

Idaho Power continued its contracts with various consultants to provide ongoing program support for lighting and non-lighting reviews and inspections, as well as contractor outreach.

The impact evaluation from 2019 recommended to: "Consider requiring pictures of the motor nameplate for the connected motor to VFD measures. The application specifies that the quantity is the lesser of the VFD or connected motor hp, it does not collect the motor hp. Motors are often in difficult to access locations, so a picture of the nameplate would help verify the motor hp." Idaho Power program staff discussed this recommendation and determined not to adopt it because in many situations obtaining a motor nameplate picture could pose a safety issue.

Marketing Activities

Idaho Power continued to primarily market the C&I Energy Efficiency Program as a single offering to businesses. See the Sector Overview for the company's efforts to market the C&I Energy Efficiency Program. Below are the option-specific marketing efforts for 2020.

Custom Projects

In addition to program-level marketing activities, Idaho Power continued to present large-format checks to interested Custom Projects participants and publicized these events to local media, when applicable. However, there were far fewer checks presented in-person in 2020 than in previous years due to COVID-19 restrictions. The company also released its Water Supply Cohort Success Story brochure and a new Custom Projects tips sheet focused on underground water leaks.

New Construction

Idaho Power placed an ad in the spring issue of the Idaho Associated General Contractors (IAGC) publication, *Building Idaho*. Accompanying the ad was an article promoting Idaho Power's New Construction incentives and highlighting a few recent projects.

The company also continued to place banners on select construction sites highlighting that the facility is being built or enhanced with energy efficiency in mind. A banner remained at St. Luke's McCall Medical Center throughout 2020.

Retrofits

In early 2020, Idaho Power launched an updated version of the Retrofits website to allow customers to easily find incentives by the following categories: lighting, HVAC/controls, food service equipment, building shell, and other. The company placed a pop-up on My Account in February that resulted in 3,553 views and 187 click-throughs from business customers.

The company used a paid LinkedIn ad to promote the Retrofits incentives in March. The ad targeted 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 65,000 individuals. The ad resulted in 51,254 impressions and 413 website clicks.

Throughout the year, the company sent out emails promoting the Retrofits lighting incentives. The company's customer solutions advisors (CSA) then followed up by making personal phone calls to customers who received the email.

Having the CSAs follow up on marketing collateral helped increase interest in the lighting incentives and is a tactic the company plans to continue in 2021.

Green Motors Initiative

In 2020, Idaho Power developed and delivered postcards for participating service centers to use to collect the information (name, telephone number, pump/pole/meter number, address) needed for the customer to receive their incentive.

The company also developed a Green Motors brochure to use in place of the brochure developed by the Green Motors Practices Group. The new brochure was specific to Idaho Power customers, included a list of participating service centers, and matched the look and feel of the other C&I Energy Efficiency Program materials.

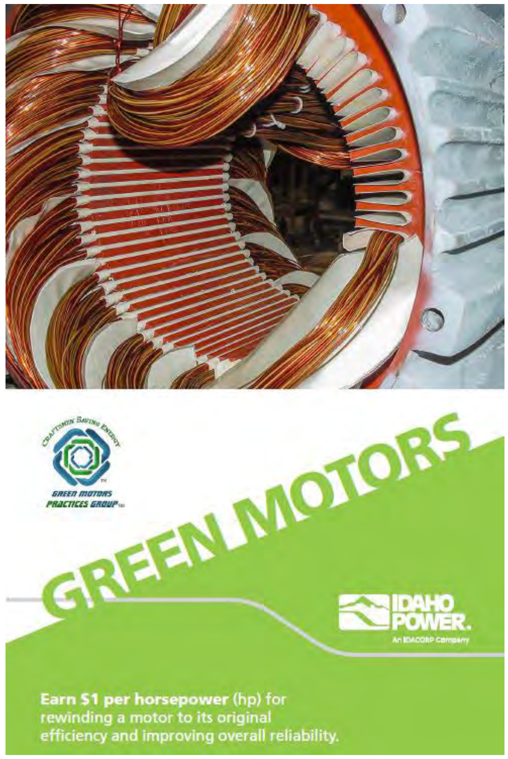

Figure 20. Green Motors brochure cover

Cost-Effectiveness

Custom Projects

Historically, all projects submitted through the Custom Projects option must meet cost-effectiveness requirements, which include TRC, UCT, and PCT tests from a project perspective. In 2020, Idaho Power began transitioning to the UCT as the primary cost-effectiveness test. The program requires that 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 an assessment, or engineering M&V services available under the Custom Projects option.

The UCT and TRC ratios for the program are 3.26 and 1.61 respectively. Non-energy impacts were applied in 2020 based on an estimated per kWh value by commercial and industrial end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options.

Details for the program 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. Because 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 from the TRC perspective. 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.

The UCT and TRC ratios for the program are 3.40 and 2.63 respectively. Non-energy impacts were applied in 2020 based on an estimated per kWh value by commercial and industrial end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options.

Complete updated measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Retrofits

For 2020, Idaho Power used most of the same savings and assumptions as were used after the program changes in 2019 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.

While all measures pass the UCT, several measures are not cost-effective from the TRC perspective. 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.

The UCT and TRC ratios for the program are 3.25 and 1.35 respectively. Non-energy impacts were applied in 2020 based on an estimated per kWh value by commercial and industrial end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options.

Complete updated measure-level details for cost effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction

Retrofits

Starting in August 2020, a survey was sent to customers who had a lighting project installed by a contractor. The purpose of the survey is to evaluate the customers' satisfaction level for the contractors listed on the Retrofits website. Survey questions gathered information about how customers learned of the program and their satisfaction with the program, contractor, and equipment.

A survey invitation was sent to 113 program participants in 2020. Idaho Power received survey results from 39 respondents. Some highlights include the following:

- Nearly 49% of respondents learned of the program from a contractor, and nearly 18% learned of the program from an Idaho Power employee.
- Nearly 90% of respondents said they were "very satisfied" with the program and almost 8% of respondents indicated they were "somewhat satisfied."
- Approximately 90% of respondents said they were "very satisfied" with the contractor they hired to install their equipment and over 5% of respondents indicated they were "somewhat satisfied."
- Just over 87% of respondents said they were "very satisfied" with the equipment installed, with just over 5% of respondents said they were "somewhat satisfied."

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

2021 Program and Marketing Strategies

In 2021, the three options will continue to be marketed as part of Idaho Power's C&I Energy Efficiency Program. Below are specific program strategies that apply to the individual options of the program.

Custom Projects

In 2021, the company plans to finalize the development of an Energy Management Commercial Audit Tool and, in conjunction with engineering services, will help identify and quantify energy savings opportunities for commercial customers. Also, the company plans to develop a compressed air leak detection and repair custom offering in 2021, similar to the water leak measure launched in 2020.

Activities and coaching will continue for the water and wastewater cohort 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-three completion scheduled for summer of 2022 and the wastewater cohort participants that have fulfilled their commitment.

Idaho Power will continue to provide:

- In-person, virtual or remote site visits and energy scoping assessments by Custom Projects engineers to identify projects and energy savings opportunities as conditions allow.
- Funding for detailed energy assessments for larger, complex projects. Virtual and/or remote assessments can also be offered in many cases.
- M&V of larger, complex projects. Virtual and/or remote M&V can also be utilized as conditions allow.
- Technical training for customers, virtually presented or in person as conditions allow.

New Construction

Idaho Power will continue to perform random post project verifications on a minimum of 10% 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. The TRM reflective of the 2018 IECC will be finalized in 2021, and Idaho Power will finalize the list of measures offered for a program update in 2021.

Retrofits

Idaho Power will implement lighting measure changes identified in 2020 and non-lighting measure changes in the updated TRM.

Commercial Energy-Saving Kits

		2020	2019
Participation and Savings			
	Participants (sites)	1,379	2,629
	Energy Savings (kWh)	258,368	569,594
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$97,645	$154,632
	Oregon Energy Efficiency Rider	$5,678	$7,312
	Idaho Power Funds	$355	$0
	Total Program Costs—All Sources	$103,678	$161,945
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.047	$0.029
	Total Resource Levelized Cost ($/kWh)	$0.047	$0.029
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.24	1.57
	Total Resource Benefit/Cost Ratio	2.38	2.52

Description

The Commercial Energy-Saving Kit (Commercial ESK) program is offered to commercial business customers in Idaho and Oregon. Three industry-specific types are available for restaurants, retailers, and offices (Table 17)—and each contains installation instructions and a variety of items intended to help save energy related to lighting, hot water use, and intermittently used electrical devices. Idaho Power uses a third-party vendor for kit assembly and mailing. The vendor sends the kit through the mail directly to the customer on the company's behalf.

Table 17. Industry-specific Commercial ESK contents

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

The vendor also batch-ships kits to area Idaho Power offices for distribution by its energy advisors. An energy advisor may then deliver a Commercial ESK while visiting a small business customer and use it as an introduction to the benefits of the other commercial energy efficiency programs offered by the company.

Program Activities

The vendor made no batch shipments in 2020, and Idaho Power conducted no in-person customer visits as of March 2020, because of COVID-19 restrictions. However, Idaho Power continued to offer

Commercial ESKs, with a primary focus on small business customers. Nearly all the kits were distributed by mail in 2020.

Idaho Power distributed 1,379 kits (Table 18), 97% of which were distributed after a customer made a request through the website or spoke with a company representative on the phone.

Table 18. Energy savings by type and number of Commercial ESKs distributed

State	Kit Type	Total Distributed	kWh Savings
Idaho	Restaurant	187	48,369
	Retail	227	54,394
	Office	887	140,607
Oregon	Restaurant	19	4,915
	Retail	9	2,157
	Office	50	7,926

Marketing Activities

Idaho Power promoted the Commercial ESKs using LinkedIn posts in May and December. A LinkedIn ad was planned for May but did not run due to technical difficulties with the LinkedIn advertising platform.

The company tried a new tactic by displaying a pop-up ad to small business customers who logged into My Account. The pop-up generated over 250 kit requests throughout an eight-week campaign that ran in June and July. Customers signing into My Account clicked on the pop up and requested a kit through the online order form. The form generated an email that was sent directly to the program specialist, who fulfilled the order.

A Retail Kit campaign launched in June with the goal of increased retail kit distribution. The program specialist created lists of retail customers sorted by the standard industrial classification code and region. The campaign asked energy advisors to call retail customers, preferably customers they had not had prior contact with. The energy advisors discussed energy efficiency program offerings and offered to ship a kit directly to the customer. The feedback received was positive, and the retail customers seem to appreciate the proactive approach and receiving the no-cost energy-efficient items.

Idaho Power launched a duplicate effort in August aimed at the restaurant industry. Some of the feedback from energy advisors included: it was harder to get ahold of customers; some were not interested; and many restaurants were operating in a difficult business climate. The restaurant industry saw significant uncertainty in 2020, as COVID-19-related restrictions impacted its bottom-line. The company's campaign did increase participation from the restaurant industry but potentially on a more limited scale than participation would have otherwise increased without COVID-19 challenges faced by restaurants.

Cost Effectiveness

Because no deemed savings values exist for the Commercial ESK program, Idaho Power made several assumptions for each kit. When the offering launched in mid-2018, the installation rates of the items in the kit was unknown. Idaho Power estimated the installation rates based on professional judgement. A follow-up survey was sent to active participants in November 2020 with an added question regarding fuel type to determine the percentage of electric water heaters. When the kits are distributed, the water heating fuel source is often unknown. Initially, Idaho Power assumed 40% of kits are distributed to businesses with electric water heat. In 2020, Idaho Power adjusted the electric water heat assumption based on information from the 2018 potential study. Idaho Power will update this assumption in 2021 based on the follow up survey sent to customers in 2020.

For the LEDs and aerators, savings vary by kit type based on the average annual HOU and annual gallons of water used by business type. Savings for the pre-rinse spray valve in the restaurant kit is from the RTF; it is adjusted based on an assumed installation rate and discounted based on the electric water heat assumption.

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

Customer Satisfaction

In November 2020, a follow-up survey was sent to past participants. The purpose of the survey was to obtain information on the customer’s water heater fuel type as well as determine if the customer had installed any of the items in the kit.

The survey was sent to 3,723 kit recipients. Idaho Power received survey results from 312 respondents. Some highlights include the following:

- The office survey was sent to 2,880 participants, with 250 respondents completing the survey. The restaurant survey was sent to 499 participants, with 37 respondents completing the survey. The retail survey was sent to 344 participants, with 25 respondents completing the survey.
- When asked what best described the water heating source at their business, almost 61% of office kit respondents, approximately 54% of restaurant kit respondents, and 60% of retail kit respondents indicated they had electric water heat.
- Of those that received an office kit, over 89% indicated they installed both LEDs in their business. Almost 94% of respondents installed the power strip.
- Of those that received a restaurant kit, over 90% said they installed all three LEDs in their business, and almost 73% installed the pre-rinse spray valve.
- Of those that received a retail kit, over 84% indicated they installed both LEDs in their business while over 60% installed both BR30 reflector LEDs.

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

2021 Program and Marketing Strategies

In 2021, Idaho Power will continue working with the third-party vendor for Commercial ESK distribution to small business customers. The marketing activities will include a LinkedIn post and an online pop up during the My Account login. Additionally, a kit will be included as one of the welcome offerings when Idaho Power calls new business customers, and the online order form will remain available through the company’s website.

Flex Peak Program

		2020	2019
Participation and Savings			
	Participants (sites)	141	145
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	24	31
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$84,716	$75,306
	Oregon Energy Efficiency Rider	$207,707	$256,606
	Idaho Power Funds	$250,056	$294,911
	Total Program Costs—All Sources	$542,480	$626,823
Program Levelized Costs			
	Utility Levelized Cost ($/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 before 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 2020, 62 participants enrolled 141 sites in the program. Existing customers were automatically re-enrolled in the program. Participants had a committed load reduction of 35.8 MW in the first week of the program and ended the season with an amount of 35.94 MW. The maximum available capacity of the program came from a nominated amount mid-season of 36.05 MW. In past years, certain events have achieved higher than a 100% realization rate, which would make this the maximum potential capacity for the program.

This weekly commitment, or nomination, was comprised of all 141 sites. The maximum realization rate during the season was 68%, and the average for the three events was 65%. 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 24.2 MW (at generation level) during the July 16 event (Table 19). The program had lower costs in 2020 over 2019 because of the slightly decreased enrolled capacity and because the actual reduction was lower in 2020 when events were called.

Table 19. Flex Peak Program demand response event details

Event Details	Thursday, July 16	Thursday, July 30	Wednesday, August 5
Event time	4–8 p.m.	4–8 p.m.	4–8 p.m.
Average temperature	93°F	102°F	93°F
Maximum load reduction (MW)	24.2	23	23.9

Event performance and realization rates for the 2020 season were significantly reduced due to the impact of COVID-19 on customer operations and their ability to reduce load. Typically, the program achieves a realization rate of 85% or greater. This year, many customers did not reduce energy use during program events because they were trying to increase production and recoup revenue after having been shut down for several months prior to the program season.

Also, many big box stores and HVAC-dependent businesses were not able to curtail load due to the need to increase the fresh air flow from outside. For example, Idaho Power Corporate Headquarters (CHQ) used more energy than normal all summer to cool the additional hot air brought in from the outside. Based on studies from the Peak Load Management Alliance, COVID-19 mitigation efforts significantly impaired commercial and industrial demand response on a national scale.

Marketing Activities

Though the terms of IPUC Order No. 32923 and OPUC Order No. 13-482 do not require program marketing, Idaho Power energy advisors regularly communicated with interested customers and current participants and encouraged them to enroll new sites. The company also continued to include the Flex Peak Program in its C&I Energy Efficiency Program collateral. Additional details can be found in the Commercial/Industrial Sector Overview.

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 Idaho Power's demand response programs were cost-effective for 2020.

The Flex Peak Program was dispatched for 12 event hours and achieved a maximum reduction of 24.2 MW. The total cost of the program in 2020 was $542,480. Had the Flex Peak Program been used for the full 60 hours, the cost would have been approximately $765,480.

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*.

2021 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 plans to focus on retaining currently enrolled participants and will consider using a My Account pop up to increase program awareness and enrollment. The program will also continue to be marketed along with the C&I Energy Efficiency Program.

The program specialist has already started working with potential candidates for the 2021 season with a focus on enrolling national chain stores within the Idaho Power service area. This customer type makes a good candidate for the program because of their extended operating hours, non-production load types, building automation controls, and consistent energy-use profiles. However, due to COVID-19, these stores may still have similar challenges with participation due to air flow as they did in 2020.

Oregon Commercial Audits

		2020	2019
Participation and Savings			
	Participants (audits)	2	11
	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	$1,374	$7,262
	Idaho Power Funds	$	$0
	Total Program Costs—All Sources	$1,374	$7,262
Program Levelized Costs			
	Utility Levelized Cost ($/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 Oregon 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 the 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

Idaho Power's contractor and personnel were available to assist customers and two customers requested and received audits by the contractor at the start of 2020. COVID-19 restrictions had a significant impact on this program in 2020, as in-person site visits were suspended between March 16 and November 16.

Marketing Activities

Idaho Power sent its annual direct-mailing to 1,566 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.

2021 Program and Marketing Strategies

Idaho Power does not expect to make any operational changes in 2021.

The company will continue to market the program through the annual customer notification and will consider additional opportunities to promote the program to eligible customers via its energy advisors.

Small Business Direct Install

		2020	2019
Participation and Savings			
	Participants (audits)	139	n/a
	Energy Savings (kWh)	780,260	n/a
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$322,463	n/a
	Oregon Energy Efficiency Rider*	$16,981	n/a
	Idaho Power Funds	$386	n/a
	Total Program Costs—All Sources	$339,830	n/a
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.058	n/a
	Total Resource Levelized Cost ($/kWh)	$0.058	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.04	n/a
	Total Resource Benefit/Cost Ratio	1.61	n/a

* Idaho activity of $15.9K charged to the Oregon Rider was reversed and charged to the Idaho rider in the first quarter of 2021.

Description

Idaho Power launched a SBDI program in November 2019 targeting typically hard-to-reach small business customers. SBDI is implemented by a third-party contractor. Idaho Power pays 100% of the cost to install eligible lighting measures for customers who use 25,000 kWh annually or less. SBDI is offered to eligible customers in a strategic geo-targeted approach.

Program Activities

In 2020, the company rolled out SBDI to customers in eastern Idaho. Three cities were targeted for the soft launch: Aberdeen, American Falls and Blackfoot. Direct-mail letters were sent to customers informing them of their eligibility to participate in the program. Follow-up calls were made to customers who received letters, offering another opportunity to hear about the program and to declare their interest in participating.

As customers responded to the letters and follow-up calls, lighting assessments were scheduled. Customers who agreed to have LEDs installed at their facility were scheduled for project installation beginning in January.

Customer interest in SBDI was on the rise when the COVID-19 pandemic occurred. Idaho Power suspended on-site customer activity for the SBDI program offering mid-March and removed the suspension early in October 2020, with on-site activity adhering to COVID-19 safety protocols. When on-site activity resumed in the fall, the company's third-party program implementer worked to reinstate equipment installers and reconnect with eligible customers who had signed up for a lighting assessment or project installation prior to COVID-19 restrictions.

There were 139 project installations performed in 2020, along with 11 post-installation inspections.

Marketing Activities

Idaho Power sent letters to 103 business customers in American Falls in January, 323 Blackfoot customers in February, 398 Blackfoot customers in March, and an additional 184 Blackfoot customers in December. The program contractor followed up with a phone call to customers about a week after they received the letter.

When on-site work was suspended due to COVID-19, the contractor reached out to the customers who were in the process to let them know the company would not be able to complete the project at that time. In August, the company sent an email to the customers who were waiting for the SBDI program to restart to let them know the on-site work remained suspended. Those customers received an email in October informing them the program had restarted, and they would receive a call from the contractor soon.

As a follow-up to the direct mail letters, over 1,000 outbound calls were placed to eligible customers, resulting in 207 scheduled lighting assessments during 2020.

Cost-Effectiveness

In 2020, the projects in the SBDI program were all lighting upgrades. Idaho Power's third-party contractor calculates the savings based on the existing fixture wattage, the replacement fixture wattage, and the HOU. The UCT and TRC ratios for the program are 1.04 and 1.61 respectively. Non-energy impacts were applied in 2020 based on an estimated per kWh value by commercial and industrial end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options.

Details for the program cost effectiveness are in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction

Idaho Power's third-party program implementer sent 96 customer satisfaction surveys to program participants in 2020, of which 27 surveys were returned. Key highlights include the following:

- Nearly 89% of respondents said they were "very satisfied" with the program, and over 7% of respondents indicated they were "somewhat satisfied."
- All respondents reported they were "very satisfied" with the equipment installed.
- All respondents found the program easy to participate in, with nearly 93% indicating the program was "very easy" and over 7% reporting it was "somewhat easy" to participate in.
- All respondents reported they would be likely to recommend the program to other small businesses, with nearly 93% saying they were "very likely" and over 7% saying they were "somewhat likely" to recommend the program.
- When asked how their opinion of Idaho Power has changed since participating in the program, just over 48% of respondents reported having a more favorable opinion of Idaho Power and nearly 52% of respondents reporting no change in opinion.

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

Evaluations

In 2020, Idaho Power contracted with Tetra Tech to conduct a process evaluation for the SBDI Program. However, due to limited program on-site installation activity because of COVID-19, it was decided the evaluation will be more informative if additional installations were completed. The contract will remain with Tetra Tech and the evaluation is estimated to resume in the second quarter of 2021.

2021 Program and Marketing Strategies

Idaho Power will continue to operate and market this program as described above. The company plans to expand the offering in its eastern region and move to the southern region mid-year 2021.

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 July 2020, the active irrigation service locations totaled 20,804 system-wide, which is an increase of 1.1% compared to July of 2019. The increase is primarily caused by adding service locations for pumps and center pivot irrigation systems as land is converted from furrow and surface irrigation to sprinkler irrigation.

Irrigation customers accounted for 1,987,418 MWh of energy usage in 2020, versus 1,759,137 MWh in 2019. The approximately 13% increase is primarily due to variations in weather. This sector represented nearly 13.5% of Idaho Power's total electricity sales, and approximately 28% of July sales. As stated above, customer numbers have increased slightly over time, while the energy usage trend for this sector has not changed significantly in many years. There is, however, a substantial yearly variation in usage due primarily to the impact of weather on irrigation customer needs.

The Irrigation Efficiency Rewards program, including the Green Motor Initiative, experienced increased annual savings: from 10,118 MWh in 2019 to 12,884 MWh in 2020. This is due primarily to an increase in the number and size of the project savings of the Custom Incentive Option.

Idaho Power re-enrolled the majority of 2019 Irrigation Peak Rewards participants in 2020, with 2,292 service points and a maximum load reduction potential of 298 MW. Table 20 shows the actual load reduction was 292 MW in 2020, and summarizes the overall expenses and program performance for both programs.

Table 20. Irrigation sector program summary, 2020

			Total Cost		Savings	
Program	**Participants**		**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response						
Irrigation Peak Rewards	2,292	service points	$ 6,407,412	$ 6,407,412		292
Total			**$ 6,407,412**	**$ 6,407,412**		**292**
Energy Efficiency						
Irrigation Efficiency Rewards	1,018	projects	$ 3,401,673	$16,857,055	12,847,823	
Green Motors—Irrigation	23	motor rewinds			36,147	
Total			**$ 3,401,673**	**$16,857,055**	**12,883,970**	

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

Energy Efficiency Programs

Irrigation Efficiency Rewards

An energy efficiency program designed to encourage customers to replace or improve inefficient irrigation systems and components. Customers receive incentives through the Custom Incentive Option for extensive retrofits and new systems and through the Menu Incentive Option for small maintenance upgrades.

Green Motor Initiative

Idaho Power pays service centers to rewind qualified irrigation motors. Half of this incentive is then given to the customer as a credit on the rewind invoice.

Demand Response Program

Irrigation Peak Rewards

A program designed to reduce peak load from irrigation pumps. Participating service points are automatically controlled by Idaho Power switches or manually interrupted by the customer when switch technology is not available.

Marketing

In 2020, the company mailed a summer edition of *Irrigation News* to all irrigation customers in its service area. In part, the newsletter educated customers about how to sign up for new or upgraded service and also promoted the Irrigation Efficiency Rewards program.

The Menu Incentive application was digitized and a tear-pad was created to make the process of distributing information and signing up for the program easier than ever.

The company also placed numerous ads in print agricultural publications to reach the target market in smaller farming communities. Publications included: *Ag Proud*, *Capital Press*, *Power County Press*, *Potato Grower Magazine*, *Owyhee Avalanche*, and *The Ag Expo East and West Programs*. Idaho Power used radio advertising to promote its presence at the Agri-Action show and to show support of Future Farmers of America and Ag Week conferences.

January through March the company ran 785 radio ads promoting the Irrigation Efficiency Rewards program. The 30-second spots ran in eastern and southern Idaho on a variety of stations, including news/talk, sports, classic rock, and country.

A tabletop display was used at irrigation-specific trade shows and highlighted specific equipment incentives. Throughout the year, social media posts promoted the company's presence at trade shows and highlighted the Irrigation Efficiency Rewards program.

Customer Satisfaction

Idaho Power conducts the *Burke Customer Relationship Survey* each year. In 2020, 62% of irrigation survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently. Seventy-one percent of respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Fifty-four percent of Idaho Power customers surveyed in 2020 indicated the company is meeting or exceeding their needs in offering energy efficiency programs, and 41% of the 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% 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 2020, prior to COVID-19 restrictions, Idaho Power provided five irrigation workshops, and participated in two additional vendor hosted workshops promoting the Irrigation Efficiency Rewards program, due to impacts of COVID-19 restrictions this number was lower than a typical year. Approximately 225 customers attended workshops in Burley, Twin Falls, Jerome, Gooding, Caldwell, Mountain Home, and Buhl, Idaho. The company also participated in and had an exhibit at four agricultural trade shows prior to COVID-19 restrictions, the Idaho Irrigation Equipment Association Winter Show, Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, and the Agri Action Ag Show.

Field Staff Activities

Idaho Power agricultural representatives (ag reps) were available to be on-site with customers offering Idaho Power energy efficiency and demand response program information, education, training, and irrigation system assessments and audits across the service area, for the first two and a half months in 2020. However, in March due to COVID-19 restrictions, ag reps were only able to stay in contact with their customers via phone call, email, and text. Later in the calendar year, because ag reps could be outdoors at customers' irrigation sites in a socially distanced manner, on-site work resumed adhering to COVID-19 safety protocols.

Also in 2020, agricultural representatives were still able to engage with agricultural irrigation equipment dealers with the goal of sharing expertise about energy-efficient system designs and increasing awareness about the program. However, due to COVID-19 restrictions this work was mostly through phone calls and emails. Agricultural representatives and the irrigation segment coordinator, a licensed agricultural engineer, participated in training to maintain or obtain their Certified Irrigation Designer and Certified Agricultural Irrigation Specialist accreditation sponsored by the nationally based Irrigation Association.

Irrigation Efficiency Rewards

		2020*	2019*
Participation and Savings			
	Participants (projects)	1,041	1,114
	Energy Savings (kWh)*	12,883,970	10,118,160
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$3,165,075	$2,449,427
	Oregon Energy Efficiency Rider	$194,044	$174,120
	Idaho Power Funds	$42,553	$37,716
	Total Program Costs—All Sources	$3,401,673	$2,661,263
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.025	$0.031
	Total Resource Levelized Cost ($/kWh)	$0.125	$0.119
Benefit/Cost Ratios**			
	Utility Benefit/Cost Ratio	4.00	2.44
	Total Resource Benefit/Cost Ratio	4.09	3.13

* 2020 total includes 36,147 kWh of energy savings from 23 Green Motors projects. 2019 total includes 44,705 kWh of energy savings from 34 Green Motors projects.

** 2020 cost-effectiveness ratios include evaluation expenses. If evaluation expenses were removed from the program's cost-effectiveness, the UCT and TRC would be 4.03 and 4.09, respectively.

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 area 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. Irrigation customers can also qualify for an incentive when they "rewind" their irrigation motors.

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% 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% 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 (sprinkler, regulator, and nozzle)
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand lines, wheel lines, and portable main lines
- New wheel-line hubs (Thunderbird)
- 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.

Green Motors Initiative

Idaho Power also participates in the Green Motors Practices Group's GMI. Under the initiative, Idaho Power pays service centers $2 per hp for motors 15 to 5,000 hp that received a verified Green Rewind. Half of that incentive is passed on to irrigation customers as a credit on their rewind invoice.

Program Activities

In 2020, 1,018 projects were completed as follows: 848 used the Menu Incentive Option and provided an estimated 4,015 MWh of energy savings; and 170 used the Custom Incentive Option and provided 8,832 MWh of energy savings (84 were new systems and 86 were on existing systems).

Also, a total of 23 irrigation customers' motors were rewound under the GMI and accounted for 36,147 kWh in savings.

Marketing Activities

In addition to training, education, and marketing activities mentioned in the Irrigation Sector Overview, the Idaho Power agricultural representative and program specialist worked one-on-one with irrigation dealers and vendors who are key to the successful promotion of the program. Due to the COVID-19 restrictions in the early spring of 2020, some of the program workshops were cancelled.

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 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% 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% on average for several irrigation hardware types. Overall, the program remains cost-effective from both the UCT and TRC perspective. Two measures pass the UCT but fail the TRC while one measure, the rebuilt or new brass sprinkler, fails both the UCT and TRC. Idaho Power received a cost-effectiveness exception with Oregon under Order No. 18-476.

The company has been working with the RTF and the irrigation subcommittee to re-examine the assumptions and review the small maintenance measures under the Menu Incentive Option offered by Idaho Power and other utilities in the region. The irrigation subcommittee created a survey to be used by regional utilities to gather better information on maintenance practices of irrigation systems. The survey is meant to be a gauge of the maintenance practices of customers participating in the program versus non-participants. Idaho Power mailed the irrigation hardware survey to Idaho Power irrigation customers in February 2020 and received a 23% response rate. The results of the survey have been compiled. Review of the survey has taken place including conversations with BPA utility representatives. The RTF's next steps with the irrigation subcommittee will be determined in the first quarter of 2021.

The UCT and TRC for the program is 4.00 and 4.09 respectively. If the amount incurred for the 2020 evaluation was removed from the program's cost-effectiveness, the UCT would be 4.03 while the TRC would be 4.09.

Complete measure-level details for cost effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Evaluations

As part of the on-going research around irrigation hardware measures, Idaho Power, in coordination with the RTF and other utilities in the region, developed a survey to gain better understanding of the hardware maintenance practices of area irrigators. Idaho Power sent surveys to 6,248 irrigators in February 2020. Key highlights from the 1,433 responses include:

- Respondents indicated that almost 84% of their acreage is irrigated with a lift greater than 200 ft.
- The most popular crops in rotation are alfalfa hay (almost 68%); barley, wheat, or other grains (over 51%); and pasture (almost 47%).
- Less than 48% of respondents replace their irrigation hardware in less than 5 years. The number of years varied by irrigation hardware measures. For pivot or linear packages, just over 38% of

respondents indicated those are replaced within 5 years. For goosenecks, just over 21% of respondents indicated those are replaced within 5 years.

- Nearly 87% of respondents indicated they do not replace their irrigation components on a predetermined schedule.

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

In 2020, Idaho Power contracted with Tetra Tech to conduct an impact and process evaluation on the Irrigation Efficiency Rewards Program. The evaluation noted the program is well-managed with comprehensive support from a knowledgeable and responsive Idaho Power staff.

The process evaluation reviewed program materials and interviewed Idaho Power program staff and agricultural representatives as well as irrigation vendors and participants. The evaluation found that materials are professional, informative and educational. Marketing messages appear to be reaching customers. The evaluation recommended Idaho Power continue transfer of documents to an electronic filing system, create a more systematic method for reviewing vendor activity levels and continue to refine the electronic program manual in case knowledgeable staff transition away from the program.

The impact evaluation calculated a 2019 program year kWh savings realization rate of 97.4% (100% for the Menu Program and 95.4% for Custom). The evaluation recommended Idaho Power formalize data collection of irrigation operating conditions, streamline custom calculations, and increase documentation for critical system components.

Idaho Power will consider all recommendations made in the report, and any changes to the program will be reported in the *Demand-Side Management 2021 Annual Report.* See the complete analysis report in *Supplement 2: Evaluation*.

2021 Program and Marketing Strategies

Irrigation Efficiency Rewards program marketing plans typically include conducting at least six customer-based irrigation workshops to promote energy efficiency, technical education, and program understanding. Though the Western Idaho Ag Expo, Agri-Action, and Idaho Irrigation Equipment Association Show & Conference are cancelled for 2021 due to COVID-19 restrictions, Idaho Power intends to participate virtually in the Eastern Idaho Ag Expo. Marketing the program to irrigation vendors will continue to be a priority.

The company will promote the program in agriculturally focused editions of newspapers, magazines, and radio ads. The radio ads will run during the spring throughout the company’s southern and eastern service areas.

Irrigation Peak Rewards

		2020	2019
Participation and Savings			
	Participants (participants)	2,292	2,332
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	292	278
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$264,843	$239,523
	Oregon Energy Efficiency Rider	$185,224	$179,733
	Idaho Power Funds	$5,957,345	$6,352,452
	Total Program Costs—All Sources	$6,407,412	$6,771,708
Program Levelized Costs			
	Utility Levelized Cost ($/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, one of the purposes 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 one or more control devices. Historically, the Irrigation Peak Rewards program provides a maximum of approximately 315 MW of load reduction, or nearly 9% of Idaho Power's all-time system peak.

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 hp or if Idaho Power has determined the AMI or cellular technology will not function properly at that location. These customers nominate a kW reduction and are compensated based on the actual load reduction during the event.

Program event guidelines for either interruption option are listed below:

- June 15 to August 15 (excluding Sundays and July 4)
- Up to four hours per day between 1 and 9 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 p.m. and 8 p.m. The variable credit is increased to $0.198/kWh when customers allow Idaho Power to interrupt their pumps until 9 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 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

In 2020, Idaho Power enrolled 2,292 (82.6%) of the eligible service points in its service area. The total nominated reduction was 400.52 MW vs. 408.65 MW in 2019. The total maximum potential reduction (capacity) for the program was 298 MW in 2020 vs 327 MW in 2019. The key factors impacting the lower maximum capacity were decreased nominated MW, decreased participation, increased device failure, and a lower percentage of enrolled pumps running on the highest day of irrigation load. Device failure identification and correction is an on-going effort pre-season and during season which requires urgency due to the strict timeline of the program. Contracted electricians continued to make site visits, however, those site visits had a slower start and were completed at a slower pace due to adhering with COVID-19 protocols.

The company used four electrical contractors during the year to maintain and troubleshoot the AMI devices and cellular devices for dispatching. Two of the four electricians were new to the program and site work involving the program. In October 2020, an effort was made to exchange nearly 211 cell devices for AMI devices due to upgrades made to substations throughout the IPC service area. Of the 211 work orders, 179 were completed and 39 are scheduled to be completed in May 2021. The exchanges will ensure a larger data set on the same technology platform, including analysis of hourly data. The cell device does not allow for monitoring on an hourly basis. The removed cell devices were retired.

Table 21. Irrigation Peak Rewards demand response event details

Event Details	Wednesday, June 24	Tuesday, July 21	Friday, July 31
Event Time	2–9 p.m.	2–9 p.m.	2–9 p.m.
Temperature	95	98	104
Maximum load reduction (MW)	292	241	226

Marketing Activities

Idaho Power used workshops, trade shows, and direct-mailings to encourage past participants to re-enroll in the program. The brochure, enrollment worksheet, and contact worksheet were mailed to all eligible participants in March 2020. 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 Idaho Power's demand response programs were cost-effective for 2020.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 292 MW. The total expense for 2020 was $6.4 million and would have been approximately $9.4 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 22. A copy of the program report is included in *Supplement 2: Evaluation*.

Table 22. Irrigation Peak Rewards program MW load reduction for events

Event Date	2–3 pm	3–4 pm	4–5 pm	5–6 pm	6–7 pm	7–8 pm	8–9 pm
6/24/2020	78.63	162.67	236.38	292.43	213.80	129.76	56.05
7/21/2020	61.75	118.38	190.55	240.52	178.77	122.14	49.97
7/31/2020	43.10	111.64	181.82	225.96	182.86	114.31	44.14

2021 Program and Marketing Strategies

Idaho Power will continue to recruit past participants in this program for the 2021 irrigation season; no program changes are expected. Because customers enroll for this program in the late winter or early spring when COVID-19 restrictions are still likely to be in place, the company's agricultural representatives will present information on the program during the virtual Eastern Idaho Ag Expo and other virtual training sessions. Each eligible customer will also be sent a comprehensive packet containing an informational brochure, enrollment worksheet, and contact worksheet encouraging their participation. Idaho Power agricultural representatives will continue to remind and inform customers to encourage program participation.

Other Programs and Activities

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 has been modifying its existing programs and expanding programs over the years to include as many cost-effective energy efficiency measures as possible for all customers. Due to the expanded options, there has been decreasing participation in the LEEF offering.

In 2020, Idaho Power received two LEEF applications for funding related to residential heating and cooling systems. Because both projects were deemed eligible for an existing energy efficiency program, an Idaho Power residential program specialist followed up with the applicants to encourage participation in the appropriate program.

Idaho Power's Internal Energy Efficiency Commitment

In 2020, Idaho Power continued to upgrade its substation buildings across the service area and prioritize the conversion to xeriscape landscaping.

Renovation projects continued at the Idaho Power CHQ in downtown Boise, with a project to exchange the old T-12 parabolic lighting fixtures with LED fixtures. Remodels continued to incorporate energy efficiency measures, such as lower partitions for better transfer of daylight, other lighting retrofits, and automated lighting controls. The CHQ building also participated in the Flex Peak Program again in 2020 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.

Market Transformation

While all Idaho Power's energy efficiency programs and activities are gradually transforming markets by changing customer's knowledge, use and application of energy efficient technologies and principles. The traditional market transformation definition 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, there is promotion of the adoption of energy-efficient materials and practices before they are integrated into building codes or become standard equipment. Idaho Power achieves market transformation savings primarily through its participation in NEEA. Although in 2020, Idaho Power and Avista did partner to engage with another third party to explore and evaluate potential opportunities or enhancements for traditional market transformation efforts that could benefit customers in both utilities service areas beyond what NEEA is currently supporting. This engagement will continue into 2021 and may lead to future efforts.

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.

Pursuant to IPUC Order No. 34556 Idaho Power participates in NEEA with funding from the Idaho Rider. The current NEEA contract is for the five years 2020-2024. NEEA categorizes the saving it achieves in five categories: total regional savings, baseline savings, local program savings, net market effects, and co-created saving created by NEEA and its utility funders working collaboratively. Of the

360–500 average megawatts (aMW) of savings forecast for 2020 to 2024, NEEA expects 70 to 100 aMW to be net market effects, and 115–152 aMW will be co-created savings. The current contract commits Idaho Power to paying NEEA $14.7 million, or approximately $2.9 million annually.

In 2020, Idaho Power participated in all of NEEA's committees and workgroups, including representation on the Regional Portfolio Advisory Committee (RPAC) and the Board of Directors. Idaho Power representatives participate in the RPAC, Cost-Effectiveness Advisory Committee, Commercial Advisory Committee, RETAC and the Idaho Energy Code Collaborative. 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 (SEM), Top-Tier Trade Ally (NXT Level), and Luminaire Level Lighting Controls (LLLC).

For the 2020-2024 funding cycle, NEEA and its funders have reorganized the "advisory" committees. NEEA now has two coordinating committees: Products Coordinating Committee and Integrated Systems Coordinating Committee. NEEA and its funders will form working groups as needed in consultation with the RPAC. The RPAC will continue, as well as the Cost Effectiveness Advisory and the Regional Emerging Technology Advisory committees. The Idaho Energy Code Collaborative will also remain intact.

NEEA performed several market progress evaluation reports (MPER) on various energy efficiency efforts this year. In addition to the MPERs, NEEA provides market research reports through third-party contractors for energy efficiency initiatives throughout the 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

To support NEEA efforts, Idaho Power educated residential customers on HPWH and DHPs and educated commercial customers and participating contractors on NXT Level Lighting Training and LLLC.

Idaho Power promoted DHPs and HPWHs as part of its H&CE Program. The company also promoted DHPs and HPWHs 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. Idaho Power posted on LinkedIn in April and August highlighting NXT Level Lighting Training. To promote LLLC, Idaho Power added a link to an informational LLLC flyer on the main Retrofits and Lighting webpages. The company also posted about LLLCs on LinkedIn in August.

NEEA Activities: All Sectors

Cost-Effectiveness Advisory Committee

The advisory group meets 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 updated since the previous reporting cycle. The committee also reviews NEEA evaluation studies and data collection strategies and previews 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 was formed to assist the Idaho Building Code Board (IBCB) in the vetting and evaluation of future versions of the IECC for the residential and commercial building sectors. The group is comprised of individuals having diverse backgrounds in the building industry and energy code development. Building energy code evaluations are presented by the group at the IBCB public meetings. The group also provides education to the building community and stakeholders to increase energy code knowledge and compliance. Idaho Power is an active member. The work is facilitated by NEEA.

On October 29, 2019, the IBCB approved 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) with amendments. The codes were on Idaho's 2020 legislative session agenda for potential adoption and were adopted with an effective date of January 1, 2021. The Idaho Energy Code Collaborative is an effort in which Idaho Power will continue to participate.

Regional Emerging Technology Advisory Committee

Idaho Power participated in the 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 2020, 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 work will continue in 2021.

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 for a program to advance to the next stage. In 2018, NEEA and RPAC formed an additional group called the RPAC Plus (RPAC+), which included marketing subject matter experts to help coordinate NEEA's marketing activities with those of the funders. RPAC convenes quarterly meetings and adds other webinars as needed.

In 2020, RPAC conducted four quarterly meetings, one that had an in-person option and the rest that were virtual due to COVID-19 restrictions. Throughout 2020, RPAC received updates of savings forecasts, portfolio priorities, committee reports, and some of the impacts of COVID-19. In addition to quarterly meetings, NEEA held a webinar workshop specifically on HPWH on February 11, 2020 to discuss tools and strategies to bolster adoption.

In the first regular quarterly meeting on March 4, NEEA held another workshop on bolstering HPWH sales in the region which resulted in a recommendation for NEEA to create an awareness/education campaign.

On June 2, NEEA staff updated RPAC on lessons learned from some Midstream Commercial Commodity Lighting pilot projects, key insights from lighting sales data, and a linear commodity lighting opportunity.

At the August 25 meeting, NEEA gave an overview of the new residential HVAC program concept, which encompasses variable capacity air source heat pumps in central forced-air applications displacing less efficient, single-speed heat pumps and electric furnaces for both retrofits and new construction. NEEA also presented market transformation progress for DHPs and shared thinking on plans to transition to Long-term Monitoring and Tracking (LTMT) and reminded RPAC that the super-efficient dryers initiative was ending in 2021. Additionally, at the RPAC+ portion of the meeting, NEEA shared the details of a proposed HPWH awareness campaign.

At the November 4 meeting, NEEA gave RPAC members an overview of the DHP program's transition to the LTMT phase. Additionally, at this meeting NEEA gave an overview of the new Variable Speed Heat Pump program that will be brought to RPAC members for an Initiative Start vote at the first quarterly meeting of 2021. NEEA also reported on the Carbon Offsets Research Work Group regarding the idea for creating carbon credits for HPWHs.

NEEA Activities: Residential

As a result of the NEEA advisory committee reorganization, the Residential Advisory Committee (RAC) was disbanded by NEEA and the tasks the committee worked on divided between the two coordinating committees: Products Coordinating Committee and Integrated Systems Coordinating Committee. The BetterBuilt NW Workgroup, which encompassed Residential New Homes and ENERGY STAR® Manufactured Homes, the Retail Products Portfolio (RPP) Initiative Workgroup and the Super-Efficient Dryers Workgroup were dissolved. Those initiatives are now included within the Product Coordinating Committee. Idaho Power is represented on both coordinating committees. Meetings were held in each quarter in 2020 for both coordinating committees. These committees provide utilities with the opportunity to give meaningful input into the design and implementation of NEEA programs as well as to productively engage with each other.

NEEA provides BetterBuiltNW online builder and contractor training, and manages the regional homes database, AXIS. NEEA continued to market an above-code manufactured homes specification, known as NEEM 2.0 to regional utilities. This specification may eventually replace the current NEEM 1.1 specification, which is dependent upon Housing and Urban Development (HUD) upgrading current code.

Residential Building Stock Assessment

NEEA began work on the Residential Building Stock Assessment (RBSA) in mid-2020. The RBSA is conducted approximately every five years. Its purpose is to determine common attributes of residential homes and to develop a profile of the existing residential buildings in the Northwest. The information is used by the regional utilities and NWPCC to determine load forecast and energy savings potential in the region.

Idaho Power participated in monthly work group meetings to discuss the study's objectives, framework, sampling design, and communication plan. It's anticipated that site visits in the region will begin in mid-2021 and will finish by mid-2022. For residential customers who choose to participate, the third-party contractor will schedule a site visit with a field technician who collects information on the home characteristics.

It is unknown when Idaho Power customers will be contacted for this study. A COVID-19 safety plan will be developed and approved by each utility prior to the start of the site visits. A final report will be available by the end of 2022.

NEEA Activities: Commercial/Industrial

NEEA continued to provide support for commercial and industrial energy efficiency activities in Idaho in 2020, which included partial funding of the IDL for trainings and additional tasks.

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 and identify opportunities to highlight above code best practice in local markets. This work will continue in 2021.

Top-Tier Trade Ally (NXT Level)

In 2020, NXT Level performed well in the region. The program continued to increase the pool of NXT Level designees. COVID-19 restrictions resulted in some increase in demand for online training; however, it also brought challenges in time and availability for participants to join the scheduled online training. NEEA updated the NXT Level 1 curriculum in 2020, as well as implemented new website resources.

Region-wide, 52 individuals were designated NXT Level 1, while 21 were newly designated NXT Level 2. Eleven companies achieved an NXT Level designation. Program-to-date, there are 335 individual NXT Level 1 and 80 NXT Level 2 designees, and 62 designated companies. In Idaho Power's service area there are 48 Level 1 individual designations, four Level 2 individual designations, and three company designations.

NXT Level 1 training was held in Pocatello in 2020 (pre-COVID-19) for the local International Brotherhood of Electrical Workers (IBEW) members. This was a pilot to see if an alternative delivery method to online was viable. The in-person training proved successful. This training resulted in 23 participants receiving Level 1 designation. Idaho Power encouraged NEEA to offer in-person NXT Level training in the future, when feasible and appropriate to do so.

Luminaire Level Lighting Controls

NEEA completed four studies in 2020: LLLC Incremental Cost Study, LLLC Market Assessment, LLLC and other Networked Lighting Controls (NLC) Energy Savings, and LLLC Replacement vs Redesign Comparison Study. These studies were provided to increase understanding of LLLC and its benefits.

NEEA assisted the implementers of Idaho State Code training to improve curriculum and educational resources related to LLLC.

NEEA partnered with the Seattle Lighting Design Lab (LDL) to offer a series of webinars on controls in 2020. Additionally, NEEA also delivered LLLC webinars in collaboration with IDL and their partner organizations, such as BOMA and the American Institute of Architects (AIA).

NEEA stated: "The LLLC program has engaged manufacturers with the objective of increasing their focus on LLLC by their sales channels in the Northwest, and four LLLC manufacturers agreed in 2020 to collaborate. While some training by manufacturers of sales agencies, distributors, and specifiers has begun, implementation was slowed in 2020 due to impacts and challenges of COVID-19. As those activities with manufacturers ramp up, it may present opportunities for collaboration with Idaho Power and other utilities."

NEEA Funding

In 2020, Idaho Power and NEEA commenced a five-year agreement for the funding cycle of 2020-2024. Per this agreement, NEEA implements market transformation programs in the company's service area. Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $14.7 million, or approximately $2.9 million annually. Of this amount in 2020, 100% was funded through the Idaho and Oregon Riders. Funding for the 2020-2024 five-year cycle was submitted to IPUC for approval on October 21, 2019. On February 20, 2020, Idaho Power received IPUC Order No. 34556, supporting Idaho Power's participation in NEEA from 2020–2024 with such participation to be funded through the Idaho Rider and subject to a prudency review.

In 2020, Idaho Power paid $2,789,210 to NEEA: $2,649,749 from the Idaho Rider for the Idaho jurisdiction and $139,460 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 2020 will be released later in the year. Preliminary estimates reported by NEEA for 2020 indicate Idaho Power's share of regional market transformation savings as 15,991 MWh. These savings are reported in two categories, 1) codes-related and standards-related savings of 13,106 MWh (82%) and 2) non codes-related and non-standards-related savings of 2,885 MWh (18%).

In the *Demand Side Management 2019 Annual Report*, preliminary funding share estimated savings reported were 18,108 MWh. The final savings included in this report for 2019 final funding-share NEEA savings is 18,368 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.

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 subcommittees, 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, ETO, 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 appeal 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 NWPCC 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 regional research findings and energy savings annually.

The current agreement to sponsor the RTF extends through 2024. Under this agreement, Idaho Power is the fourth largest RTF funder, at a rate of $713,300 for the five-year period. For this funding cycle, gas utilities and the gas portion dual-fuel utilities are also funding the RTF.

When appropriate and when the work products are applicable to the climate zones and load characteristics in Idaho Power's service area, Idaho Power uses the savings estimates, measure protocols, and supporting work documents provided by the RTF. In 2020, Idaho Power staff participated in all RTF meetings and the RTF Policy Advisory Committee.

Throughout the year, Idaho Power reviews any changes enacted by the RTF to savings, costs, or parameters for existing and proposed measures. The company then determines how the changes might be applicable to, or whether they impact, its programs and measures. The company accounted for all implemented changes in planning and budgeting for 2021.

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.

Kill A Watt Meter Program

The Kill A Watt™ Meter Program remained active in 2020. 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 21. Kill A Watt meter

Teacher Education

As in previous years, Idaho Power continued to strengthen the energy education relationship with secondary school educators through participation on the Idaho Science, Technology, Engineering, and Mathematics (iSTEM) Steering Committee. In 2020, Idaho Power and Intermountain Gas attempted to expand their reach by adding a second professional development workshop for teachers at Idaho State University's iSTEM Institute, in addition to the four day, two-credit professional development workshop offered at the College of Western Idaho's iSTEM Institute. However, due to COVID-19 restrictions, all of the 2020 iSTEM Institutes were cancelled. Both Idaho Power and Intermountain Gas have agreed to continue sponsorship of two virtual workshop sessions in 2021.

Customer Education and Marketing

REEEI produced one Energy Efficiency Guide in 2020. Idaho Power distributed the guide primarily as an insert in local newspapers. The spring/summer themed guide was published and distributed by 20 newspapers in Idaho Power's service area the week of April 25; the *Boise Weekly* also inserted the guide. The guide focused on providing answers to a number of energy efficiency questions customers had recently asked about home upgrades and do-it-yourself projects, including tips for renters and home buyers, how to get the best value for your dollar, and best practices for home water systems. Idaho Power promoted the guide on its homepage and on social media. The *Idaho Statesman* published two ads encouraging readers to look for the guide.

Figure 22. Spring/Summer edition of the *Energy Efficiency Guide*, 2020

The REEEI team investigated ways to adapt the fall/winter guide for a younger, more digitally native customer. On its website, Idaho Power provided links to current seasonal guides and past guides.

REEEI distributed energy efficiency messages through a variety of other communication methods in 2020. Idaho Power increased customer awareness of energy saving ideas via continued distribution of the fifth 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. In 2020, the program distributed 2,424 copies directly to customers. This was accomplished primarily by fulfilling direct web requests from customers, through energy advisors during in-home visits, and in response to inquiries received by Idaho Power's Customer Care Center.

Idaho Power continues to recognize that educated employees are effective advocates for energy efficiency and Idaho Power's energy efficiency programs. Idaho Power CR&EE staff reached out to each of Idaho Power's geographical regions and the Customer Care Center to speak with energy advisors and other employees to discuss educational initiatives and answer questions about the company's energy efficiency programs.

Prior to COVID-19 restrictions, Idaho Power participated in the Idaho Remodeling and Design Show; Smart Women, Smart Money; and the Canyon County winter home show. Program specialists and EOEA looked for virtual opportunities to continue sharing messages regarding low-cost and no-cost energy-saving opportunities. In 2020, despite the COVID-19 pandemic challenges, Idaho Power's EOEAs delivered over 300 presentations with energy-saving messages to audiences of all ages. Additionally, Idaho Power's energy efficiency program specialists responded with detailed answers to 231 customer questions about energy efficiency and related topics received via Idaho Power's website.

Because of COVID-19 restrictions for in-person activities, REEEI increased digital communication efforts to bring a variety of energy-saving and money-saving tips to customers. Early in the year, Idaho Power's social media channels and *News Briefs* focused on content designed to help customers save energy while spending more time at home. COVID-conscious energy efficiency tips continued through the rest of 2020, including in a December bill insert that provided all residential customers with easy steps to get their home ready for winter heating and behavior tips for reducing energy use.

Figure 23. Bill insert example

Idaho Power used multiple channels to promote National Energy Awareness Month in October, including social media posts encouraging energy-efficient behaviors and program awareness. *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 social media posts. In addition to supplying information for publications, such as

Connections and Idaho Power's social media pages, energy efficiency tips and content were provided for *News Briefs* and KTVB and KMVT live news segments focused on energy efficiency.

2021 Program and Marketing Strategies

The initiative's 2021 goals are to improve customer awareness of the wise use of energy, increase program participation, and promote educational 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. Examples of activities conducted under Educational Distributions include developing LED lighting education material, distributing LED nightlights, administering the SEEK program, Welcome Kit distribution, and the HER Program.

The initiative will continue to educate customers using a multi-channel approach 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 (idlboise.com), which 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 2020, 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. Requests for IDL involvement in building 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.

The IDL provided technical assistance on 16 new projects in the Idaho Power service area in 2020: ten Phase I projects, five Phase II projects, and one Phase III project. One of the projects was on a new building, and 15 were on existing buildings. The number of projects increased in 2020, compared to 13 in 2019, and the total building area impacted increased to approximately 385,000 ft^2, compared to 275,000 ft^2 in 2019. 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 2020, the IDL scheduled 20 technical training lunches which were conducted virtually due to COVID-19 restrictions. Ten sessions were coordinated directly with architecture and engineering firms and organizations, and 10 were available to the public; a total of 366 architects, engineers, designers, project managers, and others attended.

The topics of the lunches (and the number performed of each) were: IAQ and Energy Efficiency in Buildings (2); Daylight in Buildings: Getting the Details Right (1); Chilled Beams (1); Radiant System

Design Considerations (2); Hybrid Ground Source Heat Pump Systems (1); The Architect's Business Case for Energy Performance Modeling (2); Future of Lighting Controls (1); Luminaire Level Lighting Control (1); Daylighting Multipliers-Increasing Daylight Harvesting Efficiency (2); High-Performance Classrooms (3); Variable Refrigerant Flows (VRF) and Heat Pumps (2); Dedicated Outdoor Air Systems (1); and COVID-19 in Buildings (1). The related report is 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 2020, six monthly BSUG sessions were hosted by IDL. Five of the six sessions were hosted virtually due to COVID-19 restrictions. The sessions were attended by 12 professionals in-person and 93 professionals virtually. 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 4.20 for 2020. 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 3.5 for 2020.

Each presentation was archived on the BSUG 2.0 website along with general BSUG 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 post-project verification on 10% of the total completed C&I Energy Efficiency Program New Construction projects. In 2020, the IDL conducted a desk review of all project documentation because COVID-19 restrictions limited on-site inspections. The purpose of this verification was to confirm program guidelines and requirements help 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 desk review of all daylight photo-control incentives to improve the quality of design and installation.

Energy Resource Library

The ERL, formally Tool Loan Library (TLL), gives customers access to resources for measuring and monitoring energy use on various systems. The goal of this task was to operate and maintain the library, which includes a web-based loan tracking system, and to teach customers how to use the resources in the library.

The inventory of the ERL consists of over 900 individual pieces of equipment. In 2020, 34 new tools were added to replace old data logging models and additional analog connectors were purchased for the XC power logger series due to a compatibility issue. 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. Due to COVID-19 restrictions, a contactless pick-up and drop-off system was put into place.

In 2020, 13 of the 17 tool loan requests were completed by 10 unique users from seven locations, including three new users. The related report is in the IDL section of *Supplement 2: Evaluation*.

In 2020, Idaho Power also helped the IDL update its ERL brochure and catalog. To reduce the risk of spreading COVID-19, the catalog was published electronically with plans to distribute hard copies in 2021.

Building Energy Analytics Case Study

In 2020, the IDL was unable to complete this task as previously intended due to COVID-19 restrictions. IDL did develop a tool to normalize operational history based on weather and to locate anomalies in building energy use. Rather than weather forecasts, the lab applied historical records of weather and utility bills to develop a template that any building operator or owner can use. The user may enter the latest usage in Excel and receive visual feedback from the spreadsheet. Unlike a full analytic software package (e.g., BuildingIQ, SkySpark, or EnergyCap), the IDL spreadsheet is a simplified method to identify when building operations drift from normal performance. This tool was provided to Idaho Power, and will be made available as a free resource to its customers on the IDL website by the second quarter of 2021.

The related report for this task is located in the IDL section of *Supplement 2: Evaluation*.

RTU Control Retrofits for Small Commercial

In 2020, the IDL changed this task compared to what was previously intended due to COVID-19 restrictions. The IDL redirected its efforts to study the energy impact of COVID-19 precautions on virtual Roof Top Units (RTU). The IDL modeled specific recommendations for a typical small office with three mitigation strategies: upgrading the filter ratings, increasing the percentage of outdoor air, and increasing the amount of time the RTUs are in ventilation mode.

The related report for this task is located in the IDL section of *Supplement 2: Evaluation*.

2021 IDL Strategies

In 2021, IDL will continue work on the Foundational Services, Lunch & Learn sessions, BSUG, New Construction Verifications, ERL, and one new task, Energy Impacts of IAQ Devices.

LIST OF ACRONYMS

A/C—Air Conditioning or Air Conditioner

Ad—Advertisement

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

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BOMA—Building Owners and Managers Association

BPA—Bonneville Power Administration

BPI—Building Performance Institute

BRC—Business Reply Card

BSUG—Building Simulation Users Group

C&I—Commercial and Industrial

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCE—Commercial Code Enhancement

CCNO—Community Connection of Northeast Oregon, Inc.

CDC—Centers for Disease Control

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CFM—Cubic Feet per Minute

CHQ—Corporate Headquarters (Idaho Power)

CINA—Community in Action

COP—Coefficient of Performance

CR&EE—Customer Relations and Energy Efficiency

CSI—College of Southern Idaho

DHP—Ductless Heat Pump

DOE—US Department of Energy

DSM—Demand-Side Management

EA5—EA5 Energy Audit Program

ECM—Electronically Commutated Motor

EEAG—Energy Efficiency Advisory Group

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

EOEA—Education and Outreach Energy Advisors

ERL—Energy Resource Library

ESK—Energy-Saving Kit

ETO—Energy Trust of Oregon

ft—Feet

ft^2—Square Feet

GMI—Green Motors Initiative

GMPG—Green Motors Practice Group

gpm—Gallons per Minute

H&CE—Heating & Cooling Efficiency

HER—Home Energy Report

hp—Horsepower

HOU—Hours of Use

HPWH—Heat Pump Water Heater

HSPF—Heating Seasonal Performance Factor

HUD—Housing and Urban Development

IAQ—Indoor Air Quality

IBCA—Idaho Building Contractors Association

IBCB—Idaho Building Code Board

IBEW—International Brotherhood of Electrical Workers

ID—Idaho

IDHW—Idaho Department of Health and Welfare

IDL—Integrated Design Lab

IECC—International Energy Conservation Code

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

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

NEB—Non-Energy Benefit

NEEA—Northwest Energy Efficiency Alliance

NEEM—Northwest Energy-Efficient Manufactured Home Program

NEMA—National Electrical Manufacturers Association

NLC—Networked Lighting Controls

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

OTT—Over-the-Top

PAI—Professional Assistance Incentive

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PLC—Powerline Carrier

PR—Public Relations

PSC—Permanent Split Capacitor

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAC—Residential Advisory Committee

RCT—Randomized Control Trial

REEEI—Residential Energy Efficiency Education Initiative

RESNET—Residential Energy Services Network

RETAC—Regional Emerging Technology Advisory Committee

Rider—Energy Efficiency Rider

RIM—Ratepayer Impact Measure

RPAC—Regional Portfolio Advisory Committee

RPAC+—Regional Portfolio Advisory Committee Plus

RPP—Retail Products Portfolio

RTF—Regional Technical Forum

RTU—Rooftop Unit

SBDI—Small Business Direct Install

SCCAP—South Central Community Action Partnership

SCE—Streamlined Custom Efficiency

SEEK—Student Energy Efficiency Kits

SEICAA—Southeastern Idaho Community Action Agency

SEM—Strategic Energy Management

Simple Steps—Simple Steps, Smart Savings™

SIR—Savings-to-Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

STEM—Science, technology, engineering, and mathematics

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

USGBC—US Green Building Council

VFD—Variable Frequency Drive

VRF—Variable Refrigerant Flow

WAP—Weatherization Assistance Program

WAQC—Weatherization Assistance for Qualified Customers

WHF—Whole-House Fan

WWEEC—Wastewater Energy Efficiency Cohort

APPENDICES

Appendix 1. Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December 2020)

Idaho Energy Efficiency Rider		
2020 Beginning Balance	$	(311,045)
2020 Funding plus Accrued Interest as of 12-31-2020		28,490,581
Total 2020 Funds		**28,179,537**
2020 Expenses as of 12-31-2020		(40,409,911)
Ending Balance as of 12-31-2020	**$**	**(12,230,374)**
Oregon Energy Efficiency Rider		
2020 Beginning Balance	$	(1,154,279)
2020 Funding plus Accrued Interest as of 12-31-2020		1,946,193
Total 2020 Funds		**791,914**
2020 Expenses as of 12-31-2020		(1,786,954)
Ending Balance as of 12-31-2020	**$**	**(995,040)**
NEEA Payments		
2020 NEEA Payments as of 12-31-2020	$	2,789,210
Total	**$**	**2,789,210**

Appendix 2. 2020 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	$ 405,402	$ 25,200	$ 334,418	$ 765,020
Easy Savings: Low-Income Energy Efficiency Education	—	—	9,503	9,503
Educational Distributions	3,912,564	91,912	1,547	4,006,023
Energy Efficient Lighting	1,603,129	62,218	1,812	1,667,159
Energy House Calls	40,492	5,422	438	46,352
Heating & Cooling Efficiency Program	578,893	23,978	3,689	606,559
Home Energy Audit	128,547	—	1,999	130,546
Multifamily Energy Savings Program	83,951	4,350	1,528	89,829
Oregon Residential Weatherization	—	5,313	—	5,313
Rebate Advantage	174,670	4,897	855	180,422
Residential New Construction Pilot Program	471,542	—	1,962	473,504
Shade Tree Project	27,652	—	838	28,490
Simple Steps, Smart Savings™	93,865	3,539	1,737	99,141
Weatherization Assistance for Qualified Customers	—	—	1,385,577	1,385,577
Weatherization Solutions for Eligible Customers	198,226	—	10,489	208,715
Commercial/Industrial				
Commercial and Industrial Energy Efficiency Program				
Custom Projects	17,533,047	466,632	59,717	18,059,396
New Construction	2,278,454	98,415	7,114	2,383,983
Retrofits	3,481,992	96,323	8,962	3,587,277
Commercial Energy-Saving Kits	97,645	5,678	355	103,678
Flex Peak Program	84,716	207,707	250,056	542,480
Small Business Direct Install	322,463	16,981	386	339,830
Irrigation				
Irrigation Efficiency Rewards	3,165,075	194,044	42,553	3,401,673
Irrigation Peak Rewards	264,843	185,224	5,957,345	6,407,412
Energy Efficiency/Demand Response Total	**$ 34,947,166**	**$ 1,497,834**	**$ 8,082,880**	**$ 44,527,880**
Market Transformation				
NEEA	2,649,749	139,460	—	2,789,210
Market Transformation Total	**$ 2,649,749**	**$ 139,460**	**$ —**	**$ 2,789,210**
Other Programs and Activities				
Commercial/Industrial Energy Efficiency Overhead	393,112	20,994	8,854	422,960
Energy Efficiency Direct Program Overhead	322,964	15,228	8,555	346,747
Oregon Commercial Audit	—	1,374	—	1,374
Residential Energy Efficiency Education Initiative	209,644	11,192	2,895	223,731
Residential Energy Efficiency Overhead	985,565	50,967	5,630	1,042,162
Other Programs and Activities Total	**$ 1,911,284**	**$ 99,756**	**$ 25,935**	**$ 2,036,975**
Indirect Program Expenses				
Energy Efficiency Accounting & Analysis	929,467	48,680	199,325	1,177,471
Energy Efficiency Advisory Group	4,448	244	130	4,823
Special Accounting Entries	(32,203)	979	51,168	19,944
Indirect Program Expenses Total	**$ 901,712**	**$ 49,903**	**$ 250,623**	**$ 1,202,238**
Grand Total	**$ 40,409,911**	**$ 1,786,954**	**$ 8,359,437**	**$ 50,556,303**

Appendix 3. 2020 DSM program activity

		Total Costs		Savings			Nominal Levelized Costs [a]	
Program	Participants	Program Administrator [b]	Resource [c]	Annual Energy (kWh)	Peak Demand [d] (MW)	Measure Life (Years)	Utility ($/kWh)	Total Resource ($/kWh)
Demand Response[1]								
A/C Cool Credit	22,536 homes	$ 765,020	$ 765,020	n/a	19.4	n/a	n/a	n/a
Flex Peak Program	141 sites	542,480	542,480	n/a	24.2	n/a	n/a	n/a
Irrigation Peak Rewards	2,292 service points	6,407,412	6,407,412	n/a	292.4	n/a	n/a	n/a
Total		**$ 7,714,912**	**$ 7,714,912**		**336.1**			
Energy Efficiency								
Residential								
Easy Savings: Low-Income Energy Efficiency Education	155 HVAC tune-ups	9,503	9,503	10,628		3	0.299	0.299
Educational Distributions	97,228 kits/giveaways	3,106,820	3,106,820	9,481,801		11	0.038	0.038
Energy Efficient Lighting	1,148,061 lightbulbs	1,667,159	3,065,781	13,942,202		14	0.012	0.022
Energy House Calls	51 homes	46,352	46,352	56,944		16	0.075	0.075
Heating & Cooling Efficiency Program	1,019 projects	606,559	1,911,792	1,839,068		14	0.033	0.103
Home Energy Audit	97 audits	130,546	142,649	31,938		12	0.448	0.490
Home Energy Report Program[2]	127,138 treatment size	899,203	899,203	10,427,940		1	0.081	0.081
Multifamily Energy Savings Program	33 units	89,829	89,829	28,041		11	0.372	0.372
Oregon Residential Weatherization	0 audits/projects	5,313	5,313	0		45	n/a	n/a
Rebate Advantage	116 homes	180,422	437,263	366,678		44	0.031	0.075
Residential New Construction Pilot	248 homes	473,504	865,989	649,522		58	0.044	0.081
Shade Tree Project	0 trees	28,490	28,490	52,662		30	n/a	n/a
Simple Steps, Smart Savings™	6,894 appliances/showerheads	99,141	98,629	148,404		12	0.073	0.073
Weatherization Assistance for Qualified Customers	115 homes/non-profits	1,385,577	1,728,293	218,611		30	0.244	0.353
Weatherization Solutions for Eligible Customers	27 homes	208,715	208,715	47,360		23	0.338	0.338
Sector Total		**$ 8,937,132**	**$ 12,644,620**	**37,301,800**		**11**	**$ 0.026**	**$ 0.038**
Commercial/Industrial								
Commercial Energy-Saving Kits	1,379 kits	103,678	103,678	258,368		11	0.047	0.047
Custom Projects	169 projects	18,059,396	41,604,451	94,006,717		15	0.018	0.042
Green Motors—Industrial	10 motor rewinds			56,012		8		
New Construction	119 projects	2,383,983	4,175,611	14,565,936		12	0.018	0.031
Retrofits	630 projects	3,587,277	11,964,431	20,965,215		12	0.019	0.063
Small Business Direct Install	139 projects	339,830	339,830	780,260		9	0.058	0.058
Sector Total		**$ 24,474,163**	**$ 58,188,001**	**130,632,507**		**14**	**$ 0.019**	**$ 0.044**

Program	Participants		Total Costs: Program Administrator [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)
Irrigation									
Green Motors—Irrigation	23	motor rewinds			36,147		20	n/a	n/a
Irrigation Efficiency Reward	1,018	projects	$ 3,401,673	$ 16,857,055	12,847,823		15	$ 0.025	$ 0.125
Sector Total			**$ 3,401,673**	**$ 16,857,055**	**12,883,970**		**15**	**$ 0.025**	**$ 0.125**
Energy Efficiency Portfolio Total			**$ 36,812,968**	**$ 87,689,675**	**180,818,277**		**14**	**$ 0.021**	**$ 0.049**
Market Transformation									
Northwest Energy Efficiency Alliance (codes and standards)					13,105,699				
Northwest Energy Efficiency Alliance (other initiatives)					2,884,939				
Northwest Energy Efficiency Alliance Totals[3]			**$ 2,789,210**	**$ 2,789,210**	**15,990,638**				
Other Programs and Activities									
Residential									
Residential Energy Efficiency Education Initiative			223,731	223,731					
Commercial									
Oregon Commercial Audits	2	audits	1,374	1,374					
Other									
Energy Efficiency Direct Program Overhead			1,811,869	1,811,869					
Total Program Direct Expense			**$ 49,354,064**	**$100,230,772**	**196,808,914**	**336**			
Indirect Program Expenses			1,202,238	1,202,238					
Total DSM Expense			**$ 50,556,303**	**$101,433,010**					

[a] Levelized Costs are based on financial inputs from Idaho Power's 2017 IRP, and calculations include line-loss adjusted energy savings.
[b] The Program Administrator 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% 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 2020 will be provided by NEEA April 2021.

Appendix 4. 2020 DSM program activity by state jurisdiction

	Idaho			Oregon		
Program	**Participants**	**Program Administrator Costs**	**Demand Reduction (MW)/ Annual Energy Savings (kWh)**	**Participants**	**Program Administrator Costs**	**Demand Reduction (MW)/ Annual Energy Savings (kWh)**
Demand Response[1]						
A/C Cool Credit	22,274 homes	$ 739,720	19.2	262 homes	$ 25,300	0.2
Flex Peak Program	133 sites	334,639	16.6	8 sites	207,841	7.6
Irrigation Peak Rewards	2,241 service points	6,222,017	284.3	51 service points	185,395	8.1
Total		**$ 7,296,376**	**320**		**$ 418,536**	**16**
Energy Efficiency						
Residential						
Easy Savings: Low-Income Energy Efficiency Education	155 HVAC tune-ups	9,503	10,628	0 HVAC tune-ups		
Educational Distributions	93,707 kits/giveaways	3,014,831	9,119,114	3,521 kits/giveaways	91,989	362,287
Energy Efficient Lighting	1,103,657 lightbulbs	1,604,850	13,375,546	44,404 lightbulbs	62,309	566,656
Energy House Calls	45 homes	40,908	49,686	6 homes	5,444	7,258
Heating & Cooling Efficiency Program	1,003 projects	582,397	1,781,404	16 projects	24,162	57,665
Home Energy Audit	97 audits	130,546	31,938	0 audits		
Home Energy Report Program	127,138 treatment size	899,203	10,427,940	0 treatment size		
Multifamily Energy Savings Program	33 units	85,402	28,041	0 projects	4,427	
Oregon Residential Weatherization	n/a			0 audits/projects	5,313	0
Rebate Advantage	114 homes	175,482	361,061	2 homes	4,940	5,616
Residential New Construction Pilot Program	248 homes	473,504	649,522	0 homes		
Shade Tree Project	0 trees	28,490	52,662	0 trees		
Simple Steps, Smart Savings™	6,737 appliances/showerheads	95,515	146,986	157 appliances/showerheads	3,625	1,418
Weatherization Assistance for Qualified Customers	115 homes/non-profits	1,361,163	218,611	0 homes/non-profits	24,414	0
Weatherization Solutions for Eligible Customers	27 homes	208,715	47,360	0 homes		
Sector Total		**$ 8,710,509**	**36,300,499**		**$ 226,623**	**1,001,300**
Commercial						
Commercial Energy-Saving Kits	1,301 kits	97,982	243,370	78 kits	5,696	14,997
Custom Projects	147 projects	17,589,778	91,121,979	22 projects	469,618	2,884,738
Green Motors—Industrial	9 motor rewinds		44,235	1 motor rewinds		11,777
New Construction	110 projects	2,285,212	14,134,439	9 projects	98,771	431,497
Retrofits	613 projects	3,490,506	20,263,512	17 projects	96,771	701,703
Small Business Direct Install	139 projects	322,829	780,260	0 projects	17,001	0
Sector Total		**$ 23,786,307**	**126,587,795**		**$ 687,856**	**4,044,712**

	Idaho			Oregon		
Program	**Participants**	**Program Administrator Costs**	**Demand Reduction (MW)/ Annual Energy Savings (kWh)**	**Participants**	**Program Administrator Costs**	**Demand Reduction (MW)/ Annual Energy Savings (kWh)**
Irrigation						
Green Motors—Irrigation	20 motor rewinds		34,313	3 motor rewinds		1,834
Irrigation Efficiency Rewards	980 projects	$ 3,205,500	12,124,461	38 projects	$ 196,172	723,362
Sector Total		**$ 3,205,500**	**12,158,773**		**$ 196,172**	**725,196**
Market Transformation						
Northwest Energy Efficiency Alliance (codes and standards)			12,450,414			655,285
Northwest Energy Efficiency Alliance (other initiatives)			2,740,692			144,247
Northwest Energy Efficiency Alliance Totals[2]		**$ 2,649,749**	**15,191,106**		**$ 139,460**	**799,532**
Other Programs and Activities						
Residential						
Residential Energy Efficiency Education Initiative		212,394			11,337	
Commercial						
Oregon Commercial Audits				2 audits	1,374	
Other						
Energy Efficiency Direct Program Overhead		1,723,528			88,341	
Total Program Direct Expense		**$ 47,584,364**			**$ 1,769,700**	
Indirect Program Expenses		1,139,804			62,434	
Total Annual Savings			**190,238,174**			**6,570,740**
Total DSM Expense		**$ 48,724,168**			**$ 1,832,134**	

[a] Levelized Costs are based on financial inputs from Idaho Power's 2017 IRP and calculations include line loss adjusted energy savings.

[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 2020 will be provided by NEEA April 2021.

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DECEMBER • 2021

2021 IRP
INTEGRATED RESOURCE PLAN

A VIEW FROM ABOVE

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 *2021 Integrated Resource Plan (IRP)*.

The main document, the 2021 IRP Report, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2021 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 2020 Annual Report*, and supplemental information on Boardman to Hemingway (B2H) transmission is provided in *Appendix D–B2H Supplement,* anticipated to be filed in first quarter 2022.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

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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 nine IRPAC meetings for the 2021 IRP, with an additional three workshops that focused on various topics, such as a review of the AURORA modeling software. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power the IRP is better because of public involvement and is grateful to the individuals and groups that participated in the process.

Customer Representatives

Adler Industrial	Mike Adler
Agricultural Representative	Sid Erwin
Boise State University	Barry Burbank
Idaho National Laboratory	Kurt Myers
Micron	Jim Swier
Rule Steel	Greg Burkhardt
St. Luke's Medical	Stephanie Wicks

Public-Interest Representatives

Boise State University Energy Policy Institute	Kathleen Araujo
City of Boise	Steve Burgos
City of Nampa	Mayor Debbie Kling
Idaho Conservation League	Ben Otto
Idaho Legislature	Rep. Laurie Lickley
Idaho Office of Energy and Mineral Resources	John Chatburn
Idaho Sierra Club	Mike Heckler
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 Professor Emeritus	Clint Shock

Snake River Alliance	Chad Worth
Sun Valley Institute for Resilience	Herbert Romero

Regulatory Commission Representatives

Idaho Public Utilities Commission	Mike Louis
Public Utility Commission of Oregon	Nadine Hanhan

IRPAC Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2021	Tuesday, January 12	Energy Efficiency Subcommittee Meeting Historical Modeling of Energy Efficiency in the IRP Energy Efficiency Potential Study—Introduction & Overview Energy Efficiency & Load Forecast Discussion
2021	Tuesday, February 9	Introduction from President & CEO Lisa Grow Idaho Power Clean Energy Goal 2019 IRP in Review 2021 IRP Schedule, Process Overview, & Process Road Map 2021 IRP Carbon Outlook Valmy Unit 2 Study Outline
2021	Tuesday, February 23	Load Forecasting Workshop
2021	Thursday, March 11	Industry Topics CSPP Forecast & Assumptions Natural Gas Price Forecast Load Forecast
2021	Thursday, April 8	Operations Hydrology: RMJOC-II Part 2 Climate Change Update Operations Hydrology: Streamflow & Hydrogeneration Development Coal Unit Overview & Inputs Energy Efficiency Potential Study & Bundling Analysis Effective Load Carrying Capability: Solar, Wind & Storage Demand Response Valmy Unit 2 Study Update
2021	Thursday, April 22	AURORA Workshop
2021	Thursday, May 13	Northwest Resource Adequacy Resource Adequacy at Idaho Power Regional Transmission Overview Transmission Projects Update Future Supply-Side Resource Options
2021	Thursday, June 10	Industry Topics Transmission & Distribution Planning Topics Resource Sufficiency (IPC Flexibility & Reserve Requirements) 2020 Variable Energy Resource Integration Study Modeling Regulation Reserve Requirements IRP Modeling Scenarios Natural Gas Price Forecast Follow-Up

Meeting Dates		Agenda Items
2021	Tuesday, July 13	Power System Recent Events: 2021 Pacific Northwest Heatwave Meeting a New Peak Demand IRP Scenarios & Sensitivities Follow-Up Electrification Scenario Analysis Loss of Load Analysis & ELCC Update
2021	Tuesday, August 10	Analysis Workshop IRP Portfolio & Sensitivity Development Methodology Carbon Adder Forecasts Transmission Benefits Stochastic Risk Analysis Ideation Sessions Report-Out Demand Response Update
2021	Thursday, October 21	Analysis Check-in Preliminary Results Bridger Natural Gas Conversion
2021	Thursday, November 18	Aurora Results Update Preliminary Preferred Portfolio Validation & Verification LOLE Analysis Quantitative Risk Assessment IRP Action Plan

SALES AND LOAD FORECAST DATA

50th Percentile Annual Forecast Growth Rates

	2021–2026	2021–2031	2021–2040
Sales			
Residential Sales	0.92%	0.69%	0.77%
Commercial Sales	1.18%	0.91%	0.92%
Irrigation Sales	0.43%	0.45%	0.58%
Industrial Sales	2.82%	1.86%	1.59%
Additional Firm Sales	18.07%	12.37%	6.34%
System Sales	2.68%	2.08%	1.47%
Total Sales	2.68%	2.08%	1.47%
Loads			
Residential Load	0.90%	0.68%	0.76%
Commercial Load	1.16%	0.91%	0.91%
Irrigation Load	0.43%	0.45%	0.56%
Industrial Load	2.79%	1.85%	1.57%
Additional Firm Sales	18.07%	12.37%	6.34%
System Load Losses	1.75%	1.36%	1.11%
System Load	2.59%	2.02%	1.43%
Total Load	2.59%	2.02%	1.43%
Peaks			
System Peak	2.07%	1.69%	1.36%
Total Peak	2.07%	1.69%	1.36%
Winter Peak	2.34%	1.61%	1.23%
Summer Peak	2.07%	1.69%	1.36%
Customers			
Residential Customers	2.56%	2.26%	1.90%
Commercial Customers	2.18%	2.05%	1.84%
Irrigation Customers	1.13%	1.11%	1.07%
Industrial Customers	0.39%	0.51%	0.54%

Expected-Case Load Forecast

2021 Monthly Summary[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	830	727	605	521	468	579	724	670	523	530	680	875
Commercial	493	474	442	428	428	464	529	526	478	458	470	502
Irrigation	4	4	11	150	335	557	658	574	315	61	7	4
Industrial	283	290	286	280	284	305	303	309	300	304	302	297
Additional Firm	107	111	110	106	98	101	101	110	112	109	111	115
Loss	146	135	120	124	137	173	203	190	146	121	131	152
System Load	**1,863**	**1,741**	**1,574**	**1,609**	**1,750**	**2,180**	**2,518**	**2,380**	**1,874**	**1,583**	**1,702**	**1,946**
Light Load	1,736	1,613	1,455	1,466	1,586	1,952	2,267	2,103	1,701	1,435	1,575	1,812
Heavy Load	1,972	1,837	1,659	1,713	1,891	2,346	2,716	2,598	2,012	1,699	1,804	2,052
Total Load	**1,863**	**1,741**	**1,574**	**1,609**	**1,750**	**2,180**	**2,518**	**2,380**	**1,874**	**1,583**	**1,702**	**1,946**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,462	2,130	1,930	2,012	2,557	3,624	3,745	3,499	3,027	2,244	2,351	2,584
Total Peak Load	**2,462**	**2,130**	**1,930**	**2,012**	**2,557**	**3,624**	**3,745**	**3,499**	**3,027**	**2,244**	**2,351**	**2,584**

2022 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	848	746	620	532	475	585	725	673	525	532	685	884
Commercial	510	496	452	430	446	470	527	524	479	462	477	508
Irrigation	3	3	9	116	307	587	677	580	319	62	7	4
Industrial	298	294	295	287	292	305	306	310	302	304	303	308
Additional Firm	115	117	113	107	112	107	117	118	121	118	123	127
Loss	151	139	123	122	137	177	205	191	147	122	133	155
System Load	**1,926**	**1,794**	**1,611**	**1,595**	**1,770**	**2,231**	**2,557**	**2,396**	**1,893**	**1,600**	**1,727**	**1,987**
Light Load	1,794	1,662	1,490	1,453	1,604	1,998	2,303	2,118	1,719	1,450	1,598	1,850
Heavy Load	2,038	1,893	1,698	1,698	1,912	2,401	2,777	2,598	2,033	1,717	1,831	2,095
Total Load	**1,926**	**1,794**	**1,611**	**1,595**	**1,770**	**2,231**	**2,557**	**2,396**	**1,893**	**1,600**	**1,727**	**1,987**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,529	2,296	2,086	2,121	2,680	3,654	3,801	3,523	3,054	2,261	2,377	2,609
Total Peak Load	**2,529**	**2,296**	**2,086**	**2,121**	**2,680**	**3,654**	**3,801**	**3,523**	**3,054**	**2,261**	**2,377**	**2,609**

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 2019 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.

2023 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	859	755	625	537	480	592	735	682	530	536	690	893
Commercial	516	501	457	435	450	475	533	531	484	466	481	515
Irrigation	3	3	9	117	310	592	683	586	322	62	7	4
Industrial	309	305	307	299	305	319	320	322	314	316	315	319
Additional Firm	133	137	131	126	122	113	123	123	120	122	128	134
Loss	154	142	126	125	140	180	209	194	149	123	134	157
System Load	**1,976**	**1,845**	**1,656**	**1,639**	**1,807**	**2,271**	**2,603**	**2,437**	**1,919**	**1,626**	**1,755**	**2,023**
Light Load	1,841	1,709	1,531	1,493	1,638	2,034	2,344	2,154	1,742	1,474	1,624	1,884
Heavy Load	2,092	1,946	1,745	1,755	1,940	2,444	2,826	2,642	2,060	1,746	1,860	2,143
Total Load	**1,976**	**1,845**	**1,656**	**1,639**	**1,807**	**2,271**	**2,603**	**2,437**	**1,919**	**1,626**	**1,755**	**2,023**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,570	2,338	2,119	2,160	2,730	3,804	3,866	3,625	3,104	2,292	2,403	2,679
Total Peak Load	**2,570**	**2,338**	**2,119**	**2,160**	**2,730**	**3,804**	**3,866**	**3,625**	**3,104**	**2,292**	**2,403**	**2,679**

2024 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	871	738	631	542	485	600	746	690	534	539	694	900
Commercial	526	492	464	443	458	482	543	540	492	473	488	520
Irrigation	3	3	9	117	311	595	687	590	324	63	8	4
Industrial	320	305	316	308	314	329	329	332	324	326	324	325
Additional Firm	144	145	144	140	136	128	142	144	144	152	163	176
Loss	157	140	128	127	142	183	212	197	152	126	137	160
System Load	**2,022**	**1,824**	**1,693**	**1,676**	**1,846**	**2,317**	**2,660**	**2,494**	**1,970**	**1,678**	**1,814**	**2,085**
Light Load	1,884	1,689	1,566	1,528	1,673	2,075	2,395	2,204	1,789	1,522	1,679	1,941
Heavy Load	2,131	1,923	1,793	1,785	1,982	2,510	2,869	2,704	2,129	1,792	1,923	2,208
Total Load	**2,022**	**1,824**	**1,693**	**1,676**	**1,846**	**2,317**	**2,660**	**2,494**	**1,970**	**1,678**	**1,814**	**2,085**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,635	2,382	2,166	2,192	2,796	3,844	3,939	3,718	3,178	2,350	2,472	2,731
Total Peak Load	**2,635**	**2,382**	**2,166**	**2,192**	**2,796**	**3,844**	**3,939**	**3,718**	**3,178**	**2,350**	**2,472**	**2,731**

2025 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	878	770	634	543	487	604	752	696	536	539	695	905
Commercial	531	514	467	446	461	486	548	545	495	476	490	523
Irrigation	4	3	9	118	312	597	690	593	325	63	8	4
Industrial	325	322	322	314	319	342	343	345	337	338	337	337
Additional Firm	180	186	187	184	184	179	195	200	201	206	211	222
Loss	160	147	130	129	144	187	216	201	155	129	140	163
System Load	**2,078**	**1,942**	**1,750**	**1,735**	**1,906**	**2,395**	**2,745**	**2,579**	**2,049**	**1,751**	**1,882**	**2,155**
Light Load	1,936	1,799	1,618	1,581	1,728	2,145	2,471	2,280	1,861	1,587	1,741	2,006
Heavy Load	2,189	2,050	1,853	1,847	2,047	2,595	2,960	2,816	2,200	1,869	2,005	2,272
Total Load	**2,078**	**1,942**	**1,750**	**1,735**	**1,906**	**2,395**	**2,745**	**2,579**	**2,049**	**1,751**	**1,882**	**2,155**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,695	2,466	2,224	2,251	2,869	3,951	4,045	3,814	3,280	2,430	2,562	2,803
Total Peak Load	**2,695**	**2,466**	**2,224**	**2,251**	**2,869**	**3,951**	**4,045**	**3,814**	**3,280**	**2,430**	**2,562**	**2,803**

2026 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	887	776	637	545	489	608	758	701	538	539	697	911
Commercial	537	519	471	450	465	490	554	551	499	479	493	525
Irrigation	4	3	9	118	313	600	694	596	327	64	8	4
Industrial	337	335	333	326	330	346	347	349	341	342	341	339
Additional Firm	236	245	238	233	234	231	247	250	250	252	268	279
Loss	164	151	133	132	147	190	220	205	158	131	143	166
System Load	**2,163**	**2,029**	**1,822**	**1,805**	**1,978**	**2,465**	**2,819**	**2,651**	**2,113**	**1,807**	**1,949**	**2,224**
Light Load	2,015	1,879	1,686	1,645	1,793	2,208	2,538	2,343	1,918	1,638	1,804	2,071
Heavy Load	2,279	2,141	1,930	1,922	2,138	2,653	3,041	2,894	2,269	1,929	2,077	2,346
Total Load	**2,163**	**2,029**	**1,822**	**1,805**	**1,978**	**2,465**	**2,819**	**2,651**	**2,113**	**1,807**	**1,949**	**2,224**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,784	2,555	2,298	2,324	2,928	4,036	4,149	3,903	3,360	2,520	2,615	2,901
Total Peak Load	**2,784**	**2,555**	**2,298**	**2,324**	**2,928**	**4,036**	**4,149**	**3,903**	**3,360**	**2,520**	**2,615**	**2,901**

2027 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	895	782	639	547	491	612	765	706	540	539	698	917
Commercial	539	520	472	451	465	491	556	553	499	479	493	527
Irrigation	4	3	9	118	314	603	698	600	329	64	8	4
Industrial	339	338	336	329	333	349	350	352	344	345	344	342
Additional Firm	295	303	298	294	292	287	299	304	303	311	325	341
Loss	167	154	136	135	150	192	223	208	160	133	145	169
System Load	**2,238**	**2,101**	**1,891**	**1,874**	**2,045**	**2,534**	**2,890**	**2,722**	**2,176**	**1,871**	**2,013**	**2,301**
Light Load	2,086	1,946	1,749	1,708	1,854	2,270	2,602	2,406	1,976	1,697	1,863	2,142
Heavy Load	2,369	2,217	1,993	1,996	2,210	2,727	3,117	2,972	2,337	2,009	2,134	2,426
Total Load	**2,238**	**2,101**	**1,891**	**1,874**	**2,045**	**2,534**	**2,890**	**2,722**	**2,176**	**1,871**	**2,013**	**2,301**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,870	2,614	2,378	2,401	3,028	4,140	4,238	4,031	3,437	2,572	2,689	2,965
Total Peak Load	**2,870**	**2,614**	**2,378**	**2,401**	**3,028**	**4,140**	**4,238**	**4,031**	**3,437**	**2,572**	**2,689**	**2,965**

2028 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	904	762	642	549	493	616	772	712	542	539	700	923
Commercial	544	506	475	455	468	495	561	558	503	482	495	530
Irrigation	4	3	9	118	315	605	701	603	331	64	8	4
Industrial	343	329	339	331	336	352	352	355	347	348	347	345
Additional Firm	349	351	349	341	335	327	335	334	331	337	347	358
Loss	170	152	139	137	152	195	226	210	162	135	146	171
System Load	**2,313**	**2,103**	**1,953**	**1,932**	**2,099**	**2,589**	**2,947**	**2,772**	**2,216**	**1,905**	**2,043**	**2,332**
Light Load	2,156	1,948	1,807	1,760	1,903	2,319	2,653	2,450	2,012	1,727	1,891	2,171
Heavy Load	2,449	2,218	2,059	2,069	2,254	2,787	3,200	3,005	2,379	2,046	2,166	2,471
Total Load	**2,313**	**2,103**	**1,953**	**1,932**	**2,099**	**2,589**	**2,947**	**2,772**	**2,216**	**1,905**	**2,043**	**2,332**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,955	2,686	2,447	2,462	3,066	4,226	4,318	4,084	3,488	2,612	2,722	2,999
Total Peak Load	**2,955**	**2,686**	**2,447**	**2,462**	**3,066**	**4,226**	**4,318**	**4,084**	**3,488**	**2,612**	**2,722**	**2,999**

2029 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	913	795	645	550	494	620	778	717	543	539	701	928
Commercial	549	529	479	459	472	498	566	563	506	485	498	535
Irrigation	4	3	9	118	315	608	705	607	333	65	8	4
Industrial	345	343	342	334	339	355	356	358	350	351	350	349
Additional Firm	357	364	352	341	336	327	335	335	331	338	348	359
Loss	172	159	139	138	153	196	227	212	163	135	147	172
System Load	**2,341**	**2,193**	**1,966**	**1,941**	**2,109**	**2,604**	**2,967**	**2,790**	**2,227**	**1,912**	**2,052**	**2,347**
Light Load	2,181	2,032	1,819	1,769	1,912	2,332	2,671	2,466	2,022	1,734	1,898	2,185
Heavy Load	2,466	2,314	2,073	2,079	2,264	2,802	3,221	3,025	2,406	2,041	2,175	2,486
Total Load	**2,341**	**2,193**	**1,966**	**1,941**	**2,109**	**2,604**	**2,967**	**2,790**	**2,227**	**1,912**	**2,052**	**2,347**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	2,987	2,708	2,462	2,470	3,078	4,273	4,355	4,130	3,508	2,620	2,730	3,016
Total Peak Load	**2,987**	**2,708**	**2,462**	**2,470**	**3,078**	**4,273**	**4,355**	**4,130**	**3,508**	**2,620**	**2,730**	**3,016**

2030 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	920	800	646	551	495	622	782	720	543	537	701	933
Commercial	556	535	483	464	476	503	573	569	511	489	502	538
Irrigation	4	3	9	118	316	610	708	610	335	65	8	4
Industrial	349	347	346	338	343	359	359	361	354	355	354	352
Additional Firm	360	366	354	343	337	329	337	336	333	340	350	361
Loss	174	160	140	139	154	197	229	213	164	136	148	173
System Load	**2,362**	**2,211**	**1,978**	**1,952**	**2,120**	**2,620**	**2,988**	**2,811**	**2,239**	**1,921**	**2,062**	**2,361**
Light Load	2,201	2,048	1,830	1,779	1,922	2,346	2,690	2,484	2,033	1,742	1,908	2,198
Heavy Load	2,489	2,333	2,095	2,079	2,277	2,838	3,223	3,047	2,420	2,051	2,185	2,502
Total Load	**2,362**	**2,211**	**1,978**	**1,952**	**2,120**	**2,620**	**2,988**	**2,811**	**2,239**	**1,921**	**2,062**	**2,361**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,008	2,724	2,471	2,478	3,092	4,309	4,394	4,172	3,529	2,630	2,741	3,028
Total Peak Load	**3,008**	**2,724**	**2,471**	**2,478**	**3,092**	**4,309**	**4,394**	**4,172**	**3,529**	**2,630**	**2,741**	**3,028**

2031 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	928	806	647	551	495	624	786	724	544	535	701	938
Commercial	560	538	485	467	478	506	577	573	513	491	503	542
Irrigation	4	3	9	118	317	612	712	614	337	65	8	4
Industrial	352	350	349	341	346	362	363	365	357	358	357	356
Additional Firm	360	366	354	343	337	329	337	336	333	340	350	362
Loss	175	161	141	139	154	198	230	215	165	136	148	174
System Load	**2,379**	**2,224**	**1,986**	**1,958**	**2,127**	**2,631**	**3,004**	**2,826**	**2,248**	**1,925**	**2,067**	**2,376**
Light Load	2,217	2,060	1,837	1,785	1,928	2,356	2,705	2,497	2,041	1,745	1,912	2,212
Heavy Load	2,496	2,347	2,103	2,085	2,271	2,850	3,221	3,085	2,399	2,055	2,190	2,494
Total Load	**2,379**	**2,224**	**1,986**	**1,958**	**2,127**	**2,631**	**3,004**	**2,826**	**2,248**	**1,925**	**2,067**	**2,376**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,031	2,739	2,482	2,483	3,101	4,359	4,429	4,217	3,544	2,635	2,746	3,047
Total Peak Load	**3,031**	**2,739**	**2,482**	**2,483**	**3,101**	**4,359**	**4,429**	**4,217**	**3,544**	**2,635**	**2,746**	**3,047**

2032 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	936	782	648	550	494	625	789	726	543	533	700	942
Commercial	567	525	491	472	483	511	584	580	518	496	508	545
Irrigation	4	3	9	119	318	616	716	618	340	66	8	4
Industrial	357	342	353	345	350	366	367	369	361	362	361	360
Additional Firm	360	360	355	343	337	329	337	337	333	340	350	362
Loss	177	157	142	140	155	199	232	216	165	137	148	175
System Load	**2,400**	**2,170**	**1,997**	**1,969**	**2,138**	**2,646**	**3,026**	**2,846**	**2,260**	**1,933**	**2,075**	**2,388**
Light Load	2,237	2,010	1,847	1,794	1,938	2,370	2,724	2,515	2,052	1,752	1,920	2,223
Heavy Load	2,518	2,300	2,104	2,096	2,296	2,848	3,244	3,107	2,412	2,075	2,189	2,507
Total Load	**2,400**	**2,170**	**1,997**	**1,969**	**2,138**	**2,646**	**3,026**	**2,846**	**2,260**	**1,933**	**2,075**	**2,388**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,052	2,753	2,491	2,490	3,115	4,396	4,468	4,259	3,566	2,644	2,755	3,057
Total Peak Load	**3,052**	**2,753**	**2,491**	**2,490**	**3,115**	**4,396**	**4,468**	**4,259**	**3,566**	**2,644**	**2,755**	**3,057**

2033 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	943	815	648	549	493	625	792	728	542	530	698	946
Commercial	572	547	493	475	486	514	588	584	520	498	509	549
Irrigation	4	3	9	119	320	620	722	622	342	66	8	4
Industrial	360	358	356	348	353	370	371	373	365	366	365	364
Additional Firm	360	367	355	343	337	329	337	337	333	340	350	362
Loss	178	163	142	140	155	200	233	217	166	137	149	176
System Load	**2,416**	**2,253**	**2,003**	**1,975**	**2,146**	**2,659**	**3,043**	**2,861**	**2,268**	**1,936**	**2,080**	**2,401**
Light Load	2,252	2,087	1,853	1,800	1,945	2,381	2,740	2,529	2,059	1,755	1,924	2,236
Heavy Load	2,546	2,377	2,111	2,103	2,304	2,861	3,282	3,101	2,420	2,079	2,193	2,521
Total Load	**2,416**	**2,253**	**2,003**	**1,975**	**2,146**	**2,659**	**3,043**	**2,861**	**2,268**	**1,936**	**2,080**	**2,401**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,073	2,767	2,500	2,495	3,124	4,443	4,503	4,303	3,580	2,648	2,759	3,074
Total Peak Load	**3,073**	**2,767**	**2,500**	**2,495**	**3,124**	**4,443**	**4,503**	**4,303**	**3,580**	**2,648**	**2,759**	**3,074**

2034 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	951	820	650	550	495	631	801	736	546	533	703	954
Commercial	578	553	497	480	490	519	595	590	525	501	513	552
Irrigation	4	3	9	120	323	625	727	627	345	67	8	4
Industrial	364	362	361	353	358	374	375	377	369	370	369	368
Additional Firm	360	367	355	343	337	329	337	337	333	340	350	362
Loss	180	165	143	141	157	202	236	219	167	138	150	178
System Load	**2,437**	**2,270**	**2,015**	**1,987**	**2,159**	**2,679**	**3,070**	**2,887**	**2,285**	**1,948**	**2,093**	**2,418**
Light Load	2,271	2,103	1,863	1,811	1,957	2,400	2,764	2,551	2,074	1,766	1,936	2,251
Heavy Load	2,568	2,395	2,123	2,128	2,305	2,884	3,312	3,130	2,439	2,092	2,207	2,549
Total Load	**2,437**	**2,270**	**2,015**	**1,987**	**2,159**	**2,679**	**3,070**	**2,887**	**2,285**	**1,948**	**2,093**	**2,418**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,093	2,782	2,509	2,503	3,142	4,486	4,547	4,351	3,610	2,662	2,773	3,088
Total Peak Load	**3,093**	**2,782**	**2,509**	**2,503**	**3,142**	**4,486**	**4,547**	**4,351**	**3,610**	**2,662**	**2,773**	**3,088**

2035 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	961	829	655	555	501	639	813	747	551	535	706	962
Commercial	582	556	500	483	492	522	599	595	527	503	514	555
Irrigation	4	3	9	121	325	629	732	632	347	67	8	4
Industrial	368	366	365	357	362	379	379	382	373	374	374	373
Additional Firm	362	368	356	344	338	330	338	338	334	341	352	363
Loss	181	166	144	142	158	204	238	221	169	138	150	179
System Load	**2,459**	**2,289**	**2,029**	**2,002**	**2,176**	**2,702**	**3,100**	**2,913**	**2,301**	**1,960**	**2,105**	**2,437**
Light Load	2,292	2,121	1,877	1,824	1,972	2,420	2,791	2,575	2,089	1,777	1,947	2,269
Heavy Load	2,580	2,416	2,139	2,144	2,323	2,908	3,343	3,158	2,471	2,092	2,220	2,570
Total Load	**2,459**	**2,289**	**2,029**	**2,002**	**2,176**	**2,702**	**3,100**	**2,913**	**2,301**	**1,960**	**2,105**	**2,437**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,116	2,799	2,521	2,515	3,162	4,531	4,592	4,401	3,639	2,675	2,785	3,104
Total Peak Load	**3,116**	**2,799**	**2,521**	**2,515**	**3,162**	**4,531**	**4,592**	**4,401**	**3,639**	**2,675**	**2,785**	**3,104**

2036 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	973	809	661	560	506	648	826	757	557	538	710	971
Commercial	588	542	504	487	496	526	605	600	531	507	518	560
Irrigation	4	3	9	122	327	634	737	636	350	68	8	4
Industrial	374	358	369	361	366	383	384	387	378	379	378	378
Additional Firm	362	362	356	344	338	330	338	338	334	341	352	363
Loss	183	162	145	144	159	206	241	224	170	139	151	181
System Load	**2,483**	**2,236**	**2,045**	**2,018**	**2,193**	**2,727**	**3,131**	**2,942**	**2,319**	**1,972**	**2,117**	**2,458**
Light Load	2,314	2,072	1,892	1,839	1,988	2,442	2,819	2,600	2,106	1,788	1,959	2,288
Heavy Load	2,605	2,358	2,166	2,149	2,341	2,955	3,357	3,212	2,476	2,105	2,244	2,580
Total Load	**2,483**	**2,236**	**2,045**	**2,018**	**2,193**	**2,727**	**3,131**	**2,942**	**2,319**	**1,972**	**2,117**	**2,458**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,143	2,821	2,536	2,526	3,185	4,585	4,639	4,455	3,672	2,690	2,798	3,125
Total Peak Load	**3,143**	**2,821**	**2,536**	**2,526**	**3,185**	**4,585**	**4,639**	**4,455**	**3,672**	**2,690**	**2,798**	**3,125**

2037 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	985	848	668	566	513	658	840	769	563	542	715	980
Commercial	596	568	509	493	501	531	613	608	536	511	522	566
Irrigation	4	3	9	123	329	638	743	641	352	68	8	4
Industrial	379	376	375	366	372	389	390	392	383	385	384	384
Additional Firm	361	368	355	344	338	330	338	337	333	341	351	363
Loss	185	169	146	145	161	208	243	226	172	140	153	182
System Load	**2,509**	**2,333**	**2,063**	**2,037**	**2,213**	**2,754**	**3,166**	**2,974**	**2,340**	**1,987**	**2,132**	**2,480**
Light Load	2,338	2,161	1,908	1,856	2,006	2,467	2,851	2,628	2,125	1,802	1,973	2,308
Heavy Load	2,633	2,462	2,185	2,169	2,376	2,964	3,394	3,246	2,498	2,121	2,260	2,603
Total Load	**2,509**	**2,333**	**2,063**	**2,037**	**2,213**	**2,754**	**3,166**	**2,974**	**2,340**	**1,987**	**2,132**	**2,480**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,172	2,841	2,553	2,539	3,210	4,643	4,689	4,514	3,709	2,707	2,813	3,148
Total Peak Load	**3,172**	**2,841**	**2,553**	**2,539**	**3,210**	**4,643**	**4,689**	**4,514**	**3,709**	**2,707**	**2,813**	**3,148**

2038 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	996	858	674	572	519	668	854	781	569	545	719	989
Commercial	605	575	515	499	507	538	621	616	543	517	527	572
Irrigation	4	4	10	123	332	643	748	646	355	69	8	4
Industrial	385	382	381	372	377	395	396	398	390	391	390	389
Additional Firm	361	368	356	344	338	330	338	337	334	341	351	363
Loss	188	171	148	147	162	210	246	229	173	142	154	184
System Load	**2,538**	**2,358**	**2,083**	**2,057**	**2,235**	**2,784**	**3,204**	**3,007**	**2,363**	**2,004**	**2,150**	**2,501**
Light Load	2,365	2,185	1,927	1,875	2,026	2,494	2,884	2,658	2,145	1,817	1,989	2,328
Heavy Load	2,675	2,489	2,196	2,191	2,400	2,996	3,434	3,283	2,522	2,152	2,267	2,625
Total Load	**2,538**	**2,358**	**2,083**	**2,057**	**2,235**	**2,784**	**3,204**	**3,007**	**2,363**	**2,004**	**2,150**	**2,501**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,202	2,865	2,570	2,554	3,238	4,698	4,741	4,573	3,750	2,726	2,830	3,168
Total Peak Load	**3,202**	**2,865**	**2,570**	**2,554**	**3,238**	**4,698**	**4,741**	**4,573**	**3,750**	**2,726**	**2,830**	**3,168**

2039 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,008	868	681	578	525	678	868	792	575	549	724	998
Commercial	612	581	520	505	512	543	629	623	548	521	531	577
Irrigation	4	4	10	124	334	648	754	651	358	69	8	4
Industrial	389	387	385	377	382	400	401	403	394	396	395	395
Additional Firm	360	367	355	343	337	329	337	337	333	340	350	362
Loss	190	173	149	148	164	212	249	232	175	143	155	186
System Load	**2,564**	**2,380**	**2,100**	**2,075**	**2,254**	**2,811**	**3,238**	**3,038**	**2,383**	**2,017**	**2,163**	**2,522**
Light Load	2,389	2,205	1,942	1,891	2,044	2,517	2,915	2,685	2,163	1,829	2,002	2,348
Heavy Load	2,701	2,511	2,213	2,209	2,421	3,025	3,493	3,294	2,543	2,166	2,282	2,647
Total Load	**2,564**	**2,380**	**2,100**	**2,075**	**2,254**	**2,811**	**3,238**	**3,038**	**2,383**	**2,017**	**2,163**	**2,522**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,230	2,886	2,585	2,566	3,263	4,754	4,790	4,630	3,786	2,742	2,844	3,190
Total Peak Load	**3,230**	**2,886**	**2,585**	**2,566**	**3,263**	**4,754**	**4,790**	**4,630**	**3,786**	**2,742**	**2,844**	**3,190**

2040 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,020	848	687	584	531	688	882	804	581	552	728	1,007
Commercial	620	568	526	511	517	550	637	632	553	527	536	583
Irrigation	4	3	10	125	337	653	760	656	361	70	8	4
Industrial	396	379	391	382	388	406	407	410	400	402	401	401
Additional Firm	360	360	355	343	337	329	337	337	333	340	350	362
Loss	192	169	151	149	166	215	252	234	177	144	156	187
System Load	**2,593**	**2,329**	**2,120**	**2,095**	**2,276**	**2,841**	**3,276**	**3,073**	**2,405**	**2,034**	**2,180**	**2,544**
Light Load	2,416	2,157	1,961	1,909	2,063	2,544	2,949	2,715	2,184	1,844	2,017	2,369
Heavy Load	2,732	2,456	2,234	2,244	2,430	3,057	3,533	3,331	2,582	2,171	2,299	2,683
Total Load	**2,593**	**2,329**	**2,120**	**2,095**	**2,276**	**2,841**	**3,276**	**3,073**	**2,405**	**2,034**	**2,180**	**2,544**
Peak Load (MW) 90th Percentile												
System Peak Load (1 hour)	3,262	2,910	2,603	2,580	3,291	4,814	4,842	4,692	3,826	2,761	2,860	3,214
Total Peak Load	**3,262**	**2,910**	**2,603**	**2,580**	**3,291**	**4,814**	**4,842**	**4,692**	**3,826**	**2,761**	**2,860**	**3,214**

Annual Summary

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Billed Sales (MWh) 50th Percentile										
Residential	5,635,713	5,710,186	5,772,357	5,834,308	5,864,905	5,898,453	5,931,181	5,967,746	5,999,109	6,018,724
Commercial	4,154,365	4,217,870	4,263,448	4,334,031	4,365,752	4,404,485	4,412,187	4,445,191	4,478,255	4,524,186
Irrigation	1,970,226	1,965,458	1,983,439	1,994,283	2,002,695	2,012,609	2,022,833	2,032,511	2,041,379	2,050,717
Industrial	2,580,373	2,623,201	2,730,455	2,816,579	2,897,217	2,965,928	2,992,099	3,017,063	3,044,712	3,074,987
Additional Firm	942,656	1,018,694	1,104,071	1,288,348	1,705,710	2,163,300	2,667,909	2,996,219	3,009,581	3,025,290
System Load	**15,283,333**	**15,535,409**	**15,853,770**	**16,267,549**	**16,836,279**	**17,444,775**	**18,026,210**	**18,458,730**	**18,573,037**	**18,693,904**
Total Load	**15,283,333**	**15,535,409**	**15,853,770**	**16,267,549**	**16,836,279**	**17,444,775**	**18,026,210**	**18,458,730**	**18,573,037**	**18,693,904**
Generation Month Sales (MWh) 50th Percentile										
Residential	5,643,792	5,715,460	5,777,754	5,837,430	5,868,421	5,902,080	5,935,286	5,971,643	6,002,306	6,022,165
Commercial	4,157,604	4,220,547	4,267,693	4,335,826	4,367,986	4,404,768	4,414,055	4,447,059	4,480,927	4,525,422
Irrigation	1,969,952	1,965,473	1,983,447	1,994,290	2,002,703	2,012,617	2,022,841	2,032,518	2,041,387	2,050,724
Industrial	2,586,804	2,631,598	2,738,356	2,820,809	2,906,038	2,968,139	2,994,178	3,019,425	3,047,267	3,077,338
Additional Firm	942,656	1,018,694	1,104,071	1,288,348	1,705,710	2,163,300	2,667,909	2,996,219	3,009,581	3,025,290
System Sales	**15,300,808**	**15,551,772**	**15,871,321**	**16,276,703**	**16,850,858**	**17,450,904**	**18,034,270**	**18,466,864**	**18,581,468**	**18,700,939**
Total Sales	**15,300,808**	**15,551,772**	**15,871,321**	**16,276,703**	**16,850,858**	**17,450,904**	**18,034,270**	**18,466,864**	**18,581,468**	**18,700,939**
Loss	1,299,774	1,317,582	1,339,261	1,364,116	1,390,580	1,417,751	1,441,898	1,462,314	1,471,333	1,480,536
Required Generation	**16,600,582**	**16,869,354**	**17,210,583**	**17,640,819**	**18,241,438**	**18,868,655**	**19,476,169**	**19,929,178**	**20,052,801**	**20,181,475**
Average Load (aMW) 50th Percentile										
Residential	644	652	660	665	670	674	678	680	685	687
Commercial	475	482	487	494	499	503	504	506	512	517
Irrigation	225	224	226	227	229	230	231	231	233	234
Industrial	295	300	313	321	332	339	342	344	348	351
Additional Firm	108	116	126	147	195	247	305	341	344	345
Loss	148	150	153	155	159	162	165	166	168	169
System Load	**1,895**	**1,926**	**1,965**	**2,008**	**2,082**	**2,154**	**2,223**	**2,269**	**2,289**	**2,304**
Light Load	1,727	1,755	1,790	1,830	1,898	1,963	2,026	2,068	2,086	2,100
Heavy Load	2,027	2,060	2,102	2,148	2,227	2,304	2,378	2,427	2,448	2,463
Total Load	**1,895**	**1,926**	**1,965**	**2,008**	**2,082**	**2,154**	**2,223**	**2,269**	**2,289**	**2,304**
Peak Load (MW) 90th Percentile										
System Peak (1 hour)	3,745	3,801	3,866	3,939	4,045	4,149	4,238	4,318	4,355	4,394
Total Peak Load	**3,745**	**3,801**	**3,866**	**3,939**	**4,045**	**4,149**	**4,238**	**4,318**	**4,355**	**4,394**

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
					Billed Sales (MWh) 50th Percentile					
Residential	6,038,740	6,053,331	6,061,524	6,104,752	6,167,697	6,234,707	6,307,610	6,379,036	6,451,389	6,524,479
Commercial	4,547,247	4,597,454	4,623,819	4,666,477	4,691,896	4,730,777	4,781,058	4,840,659	4,891,067	4,946,878
Irrigation	2,059,844	2,072,374	2,087,185	2,102,102	2,117,049	2,132,249	2,148,024	2,163,705	2,180,446	2,197,856
Industrial	3,102,840	3,139,967	3,172,009	3,209,971	3,246,433	3,287,987	3,335,272	3,388,295	3,429,735	3,483,237
Additional Firm	3,026,907	3,032,142	3,027,782	3,028,582	3,039,830	3,043,140	3,034,836	3,036,125	3,028,047	3,032,367
System Load	**18,775,578**	**18,895,269**	**18,972,319**	**19,111,884**	**19,262,906**	**19,428,860**	**19,606,800**	**19,807,820**	**19,980,685**	**20,184,816**
Total Load	**18,775,578**	**18,895,269**	**18,972,319**	**19,111,884**	**19,262,906**	**19,428,860**	**19,606,800**	**19,807,820**	**19,980,685**	**20,184,816**
					Generation Month Sales (MWh) 50th Percentile					
Residential	6,038,740	6,053,331	6,061,524	6,104,752	6,167,697	6,234,707	6,307,610	6,379,036	6,451,389	6,524,479
Commercial	4,547,247	4,597,454	4,623,819	4,666,477	4,691,896	4,730,777	4,781,058	4,840,659	4,891,067	4,946,878
Irrigation	2,059,844	2,072,374	2,087,185	2,102,102	2,117,049	2,132,249	2,148,024	2,163,705	2,180,446	2,197,856
Industrial	3,102,840	3,139,967	3,172,009	3,209,971	3,246,433	3,287,987	3,335,272	3,388,295	3,429,735	3,483,237
Additional Firm	3,026,907	3,032,142	3,027,782	3,028,582	3,039,830	3,043,140	3,034,836	3,036,125	3,028,047	3,032,367
System Sales	**18,775,578**	**18,895,269**	**18,972,319**	**19,111,884**	**19,262,906**	**19,428,860**	**19,606,800**	**19,807,820**	**19,980,685**	**20,184,816**
Total Sales	**18,775,578**	**18,895,269**	**18,972,319**	**19,111,884**	**19,262,906**	**19,428,860**	**19,606,800**	**19,807,820**	**19,980,685**	**20,184,816**
Loss	1,487,351	1,496,764	1,503,299	1,515,098	1,527,602	1,541,794	1,557,512	1,574,430	1,589,893	1,607,050
Required Generation	**20,272,221**	**20,399,203**	**20,484,525**	**20,635,958**	**20,801,018**	**20,982,844**	**21,177,403**	**21,393,841**	**21,583,530**	**21,804,967**
					Average Load (aMW) 50th Percentile					
Residential	690	689	692	697	705	710	721	729	737	743
Commercial	519	524	528	533	536	539	546	553	559	564
Irrigation	235	236	238	240	242	243	245	247	249	250
Industrial	355	358	362	367	371	375	381	387	392	397
Additional Firm	346	345	346	346	347	346	346	347	346	345
Loss	170	170	172	173	174	176	178	180	181	183
System Load	**2,314**	**2,322**	**2,338**	**2,356**	**2,375**	**2,389**	**2,418**	**2,442**	**2,464**	**2,482**
Light Load	2,109	2,117	2,131	2,147	2,164	2,177	2,203	2,226	2,246	2,262
Heavy Load	2,468	2,477	2,494	2,513	2,532	2,548	2,578	2,605	2,628	2,648
Total Load	**2,314**	**2,322**	**2,338**	**2,356**	**2,375**	**2,389**	**2,418**	**2,442**	**2,464**	**2,482**
					Peak Load (MW) 90th Percentile					
System Peak (1 hour)	4,429	4,468	4,503	4,547	4,592	4,639	4,689	4,741	4,790	4,842
Total Peak Load	**4,429**	**4,468**	**4,503**	**4,547**	**4,592**	**4,639**	**4,689**	**4,741**	**4,790**	**4,842**

LOAD AND RESOURCE BALANCE DATA

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Peak-Hour (50th+15.5%) w/EE	(2,693)	(2,339)	(2,172)	(2,064)	(2,757)	(3,938)	(4,161)	(3,899)	(3,259)	(2,453)	(2,525)	(2,733)
Existing Demand Response Capacity	–	–	–	–	–	66	66	58	–	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(2,693)**	**(2,339)**	**(2,172)**	**(2,064)**	**(2,757)**	**(3,873)**	**(4,096)**	**(3,840)**	**(3,259)**	**(2,453)**	**(2,525)**	**(2,733)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	121	121	121	121	121	121	121
Total Coal	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**
Langley Gulch	288	282	279	279	276	270	270	270	273	276	282	288
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**717**	**708**	**689**	**680**	**672**	**640**	**636**	**637**	**671**	**691**	**706**	**725**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	356	366	285	431	458	434	295	254	244	218	200	378
Total Hydroelectric (50%)	**1,368**	**1,378**	**1,346**	**1,492**	**1,615**	**1,591**	**1,355**	**1,266**	**1,159**	**1,086**	**875**	**1,342**
Solar CSPP (PURPA)	–	–	99	99	99	197	197	197	99	99	99	–
Wind CSPP Capacity	94	94	94	94	94	93	93	93	94	94	94	94
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**125**	**133**	**239**	**276**	**314**	**424**	**420**	**412**	**296**	**260**	**227**	**126**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	–	–	–	–	–	–	–	–	–	–
Clatskanie Exchange	–	–	–	–	–	14	11	2	–	–	–	–
Total PPAs	**50**	**50**	**48**	**46**	**38**	**52**	**42**	**38**	**41**	**46**	**51**	**52**
Available Transmission w/3rd Party Secured	**50**	**50**	**50**	**50**	**150**	**200**	**200**	**200**	**200**	**200**	**150**	**150**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,424**	**3,434**	**3,486**	**3,657**	**3,904**	**4,021**	**3,767**	**3,667**	**3,481**	**3,397**	**3,123**	**3,510**
Monthly Surplus/Deficit	**731**	**1,095**	**1,314**	**1,594**	**1,147**	**148**	**(329)**	**(173)**	**222**	**944**	**598**	**776**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 4 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Storage)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—WY Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—ID Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	–	–	–	–	–	–	–	–	–	–	–	–
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	731	1,095	1,314	1,594	1,147	148	(329)	(173)	222	944	598	776
Planning Margin	46.8%	69.6%	85.4%	104.7%	63.6%	19.9%	6.4%	10.4%	23.4%	59.9%	42.9%	48.3%

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Peak-Hour (50th+15.5%) w/EE	(2,771)	(2,531)	(2,352)	(2,188)	(2,899)	(3,973)	(4,226)	(3,927)	(3,291)	(2,473)	(2,555)	(2,762)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(2,771)**	**(2,531)**	**(2,352)**	**(2,188)**	**(2,899)**	**(3,798)**	**(4,050)**	**(3,800)**	**(3,188)**	**(2,473)**	**(2,555)**	**(2,762)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	121	121	121	121	121	121	121
Total Coal	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**
Langley Gulch	288	282	279	279	276	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**717**	**708**	**689**	**680**	**672**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	356	366	286	431	461	437	295	254	244	218	200	379
Total Hydroelectric (50%)	**1,368**	**1,378**	**1,346**	**1,492**	**1,618**	**1,594**	**1,355**	**1,266**	**1,159**	**1,086**	**875**	**1,343**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	94	94	94	94	94	93	93	93	94	94	94	94
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**125**	**133**	**240**	**276**	**316**	**425**	**422**	**414**	**297**	**261**	**228**	**126**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	–	–	–	–	–	–	–	–	–	–
Clatskanie Exchange	–	–	–	–	–	14	11	2	–	–	–	–
Total PPAs	**50**	**50**	**48**	**46**	**38**	**52**	**42**	**38**	**41**	**46**	**51**	**52**
Available Transmission w/3rd Party Secured	**150**	**150**	**150**	**150**	**250**	**300**	**300**	**300**	**300**	**300**	**250**	**209**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,524**	**3,534**	**3,588**	**3,758**	**4,008**	**4,161**	**3,904**	**3,804**	**3,618**	**3,533**	**3,259**	**3,605**
Monthly Surplus/Deficit	**753**	**1,003**	**1,236**	**1,570**	**1,109**	**364**	**(146)**	**4**	**430**	**1,060**	**705**	**843**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 4 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Storage)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—WY Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—ID Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	–	–	–	–	–	–	–	–	–	–	–	–
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**753**	**1,003**	**1,236**	**1,570**	**1,109**	**364**	**(146)**	**4**	**430**	**1,060**	**705**	**843**
Planning Margin	**46.9%**	**61.3%**	**76.2%**	**98.4%**	**59.7%**	**26.1%**	**11.5%**	**15.6%**	**30.6%**	**65.0%**	**47.4%**	**50.8%**

	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Peak-Hour (50th+15.5%) w/EE	(2,818)	(2,579)	(2,390)	(2,234)	(2,956)	(4,146)	(4,301)	(4,045)	(3,348)	(2,509)	(2,585)	(2,843)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(2,818)**	**(2,579)**	**(2,390)**	**(2,234)**	**(2,956)**	**(3,971)**	**(4,126)**	**(3,917)**	**(3,245)**	**(2,509)**	**(2,585)**	**(2,843)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	121	121	121	121	121	121	121
Total Coal	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	356	366	287	431	464	443	295	254	244	218	200	381
Total Hydroelectric (50%)	**1,368**	**1,378**	**1,347**	**1,492**	**1,621**	**1,599**	**1,355**	**1,266**	**1,159**	**1,086**	**875**	**1,345**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	94	94	94	94	94	93	93	93	94	94	94	94
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**125**	**133**	**240**	**276**	**316**	**425**	**422**	**414**	**297**	**261**	**228**	**126**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	14	11	2	–	–	–	–
Total PPAs	**50**	**50**	**68**	**66**	**58**	**92**	**82**	**78**	**61**	**66**	**71**	**52**
Available Transmission w/3rd Party Secured	**239**	**295**	**330**	**330**	**271**	**380**	**380**	**380**	**380**	**380**	**275**	**206**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,648**	**3,714**	**3,825**	**3,994**	**4,088**	**4,287**	**4,025**	**3,925**	**3,718**	**3,634**	**3,305**	**3,605**
Monthly Surplus/Deficit	**830**	**1,135**	**1,435**	**1,760**	**1,132**	**316**	**(101)**	**8**	**473**	**1,125**	**720**	**762**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	7	7	5	4	–	–	–
New Resource—Battery: 4 hour	50	50	50	101	101	101	101	101	50	50	50	50
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Storage)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—WY Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—ID Wind	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	–	–	–	–	–	–	–	–	–	–	–	–
New Resource Subtotal	50	50	50	50	101	108	108	106	105	50	50	50
Monthly Surplus/Deficit	**881**	**1,185**	**1,485**	**1,810**	**1,232**	**424**	**7**	**114**	**578**	**1,175**	**770**	**812**
Planning Margin	**51.6%**	**68.6%**	**87.2%**	**109.1%**	**63.6%**	**27.3%**	**15.7%**	**18.7%**	**35.4%**	**69.6%**	**49.9%**	**48.5%**

	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Peak-Hour (50th+15.5%) w/EE	(2,893)	(2,630)	(2,444)	(2,271)	(3,033)	(4,192)	(4,385)	(4,152)	(3,433)	(2,576)	(2,664)	(2,902)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(2,893)**	**(2,630)**	**(2,444)**	**(2,271)**	**(3,033)**	**(4,017)**	**(4,210)**	**(4,025)**	**(3,330)**	**(2,576)**	**(2,664)**	**(2,902)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	121	121	121	121	121	121	121
Total Coal	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	357	366	289	432	466	446	295	253	244	218	200	383
Total Hydroelectric (50%)	**1,369**	**1,379**	**1,349**	**1,492**	**1,623**	**1,603**	**1,355**	**1,266**	**1,159**	**1,085**	**875**	**1,347**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	94	94	94	94	94	93	93	93	94	94	94	94
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**125**	**133**	**240**	**276**	**316**	**425**	**422**	**414**	**297**	**261**	**228**	**126**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	14	11	2	–	–	–	–
Total PPAs	**50**	**50**	**68**	**66**	**58**	**92**	**82**	**78**	**61**	**66**	**71**	**52**
Available Transmission w/3rd Party Secured	**237**	**294**	**330**	**330**	**269**	**380**	**379**	**380**	**380**	**380**	**273**	**205**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,647**	**3,714**	**3,826**	**3,994**	**4,088**	**4,290**	**4,023**	**3,925**	**3,718**	**3,633**	**3,303**	**3,604**
Monthly Surplus/Deficit	**754**	**1,083**	**1,382**	**1,723**	**1,056**	**274**	**(186)**	**(100)**	**388**	**1,058**	**639**	**702**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	7	7	5	4	–	–	–
New Resource—Battery: 4 hour	53	53	53	53	105	105	105	105	105	53	53	53
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Storage)	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar	–	–	–	–	–	–	–	–	–	10	10	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	334	334	334	334	334	334	334
Early Bridger Coal Exits	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)
New Resource Subtotal	(204)	(204)	(204)	(204)	(151)	190	190	188	187	141	141	131
Monthly Surplus/Deficit	**550**	**879**	**1,178**	**1,520**	**904**	**464**	**4**	**88**	**575**	**1,198**	**779**	**833**
Planning Margin	**37.5%**	**54.1%**	**71.2%**	**92.8%**	**49.9%**	**28.3%**	**15.6%**	**18.0%**	**34.8%**	**69.2%**	**49.3%**	**48.6%**

	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Peak-Hour (50th+15.5%) w/EE	(2,962)	(2,727)	(2,512)	(2,339)	(3,118)	(4,316)	(4,508)	(4,263)	(3,551)	(2,669)	(2,768)	(2,986)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(2,962)**	**(2,727)**	**(2,512)**	**(2,339)**	**(3,118)**	**(4,140)**	**(4,332)**	**(4,135)**	**(3,448)**	**(2,669)**	**(2,768)**	**(2,986)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	121	121	121	121	121	121	121	121	121	121	121	121
Total Coal	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**	**784**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	356	366	288	431	466	445	295	253	243	218	200	382
Total Hydroelectric (50%)	**1,369**	**1,378**	**1,349**	**1,492**	**1,623**	**1,602**	**1,355**	**1,266**	**1,159**	**1,085**	**875**	**1,346**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	94	94	94	94	94	93	93	93	94	93	93	93
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**125**	**133**	**240**	**276**	**316**	**425**	**422**	**414**	**297**	**259**	**227**	**125**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	14	11	2	–	–	–	–
Total PPAs	**50**	**50**	**68**	**66**	**58**	**92**	**82**	**78**	**61**	**66**	**71**	**52**
Available Transmission w/3rd Party Secured	**235**	**290**	**330**	**330**	**268**	**380**	**377**	**380**	**380**	**379**	**271**	**203**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,645**	**3,710**	**3,826**	**3,994**	**4,086**	**4,289**	**4,021**	**3,925**	**3,718**	**3,631**	**3,300**	**3,601**
Monthly Surplus/Deficit	**683**	**983**	**1,314**	**1,654**	**968**	**149**	**(311)**	**(211)**	**269**	**962**	**531**	**614**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	55	55	55	55	109	109	109	109	109	55	55	55
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	5	5	5	10	10	10	5	5	5	–
New Resource—Solar + Storage 1:1 (Storage)	43	43	43	43	87	87	87	87	87	43	43	43
New Resource—Solar	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)	(334)
New Resource Subtotal	176	176	191	191	290	319	319	315	298	191	191	176
Monthly Surplus/Deficit	**859**	**1,160**	**1,505**	**1,846**	**1,258**	**468**	**8**	**105**	**567**	**1,154**	**723**	**791**
Planning Margin	**49.0%**	**64.6%**	**84.7%**	**106.6%**	**62.1%**	**28.0%**	**15.7%**	**18.3%**	**34.0%**	**65.4%**	**45.7%**	**46.1%**

	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Peak-Hour (50th+15.5%) w/EE	(3,065)	(2,829)	(2,598)	(2,423)	(3,186)	(4,415)	(4,620)	(4,358)	(3,636)	(2,765)	(2,822)	(3,092)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,065)**	**(2,829)**	**(2,598)**	**(2,423)**	**(3,186)**	**(4,239)**	**(4,445)**	**(4,231)**	**(3,533)**	**(2,765)**	**(2,822)**	**(3,092)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	356	365	288	431	465	445	294	253	243	218	200	380
Total Hydroelectric (50%)	**1,368**	**1,378**	**1,348**	**1,491**	**1,622**	**1,601**	**1,355**	**1,265**	**1,159**	**1,085**	**875**	**1,344**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	93	93	92	92	92	91	91	91	92	92	92	92
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**124**	**132**	**238**	**274**	**313**	**423**	**420**	**412**	**295**	**258**	**226**	**124**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**50**	**50**	**68**	**66**	**58**	**78**	**71**	**76**	**61**	**66**	**71**	**52**
Available Transmission w/3rd Party Secured	**233**	**289**	**330**	**330**	**266**	**380**	**375**	**380**	**380**	**277**	**170**	**102**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,520**	**3,585**	**3,702**	**3,870**	**3,961**	**4,152**	**3,885**	**3,799**	**3,594**	**3,407**	**3,076**	**3,375**
Monthly Surplus/Deficit	**455**	**756**	**1,105**	**1,447**	**775**	**(88)**	**(560)**	**(432)**	**61**	**642**	**253**	**283**
2021 IRP Resources												
New Transmission—B2H	–	–	–	–	–	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	55	55	55	55	109	109	109	109	109	55	55	55
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	5	5	5	10	10	10	5	5	5	–
New Resource—Solar + Storage 1:1 (Storage)	43	43	43	43	87	87	87	87	87	43	43	43
New Resource—Solar	–	–	21	21	21	42	42	42	21	21	27	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)
New Resource Subtotal	13	13	39	39	138	678	678	674	646	439	445	413
Monthly Surplus/Deficit	**468**	**769**	**1,144**	**1,486**	**912**	**591**	**118**	**242**	**707**	**1,081**	**699**	**696**
Planning Margin	**33.1%**	**46.9%**	**66.4%**	**86.4%**	**48.6%**	**30.9%**	**18.5%**	**21.9%**	**37.9%**	**60.7%**	**44.1%**	**41.5%**

	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Peak-Hour (50th+15.5%) w/EE	(3,157)	(2,890)	(2,682)	(2,505)	(3,294)	(4,527)	(4,724)	(4,506)	(3,725)	(2,825)	(2,907)	(3,166)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,157)**	**(2,890)**	**(2,682)**	**(2,505)**	**(3,294)**	**(4,351)**	**(4,548)**	**(4,379)**	**(3,622)**	**(2,825)**	**(2,907)**	**(3,166)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	355	364	287	431	465	443	294	253	243	218	200	377
Total Hydroelectric (50%)	**1,367**	**1,376**	**1,347**	**1,491**	**1,621**	**1,600**	**1,355**	**1,265**	**1,159**	**1,085**	**874**	**1,341**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	92	92	92	92	92	91	91	91	92	92	92	92
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**123**	**131**	**238**	**274**	**313**	**423**	**420**	**412**	**295**	**258**	**226**	**124**
Elkhorn	15	15	15	15	15	15	15	15	15	15	15	15
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**50**	**50**	**68**	**66**	**58**	**78**	**71**	**76**	**61**	**66**	**71**	**52**
Available Transmission w/3rd Party Secured	**132**	**187**	**250**	**258**	**165**	**380**	**374**	**380**	**380**	**276**	**169**	**101**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,416**	**3,481**	**3,621**	**3,798**	**3,858**	**4,150**	**3,883**	**3,799**	**3,594**	**3,406**	**3,074**	**3,371**
Monthly Surplus/Deficit	**259**	**591**	**939**	**1,293**	**565**	**(201)**	**(665)**	**(580)**	**(28)**	**581**	**167**	**205**
2021 IRP Resources												
New Transmission—B2H	400	400	400	699	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	57	57	57	57	114	114	114	114	114	57	57	57
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	5	5	5	10	10	10	5	5	5	–
New Resource—Solar + Storage 1:1 (Storage)	43	43	43	43	87	87	87	87	87	43	43	43
New Resource—Solar	–	–	27	27	27	68	68	68	34	34	34	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)
New Resource Subtotal	415	415	447	746	848	708	708	704	663	454	454	415
Monthly Surplus/Deficit	**675**	**1,006**	**1,386**	**2,039**	**1,413**	**507**	**44**	**124**	**635**	**1,035**	**622**	**621**
Planning Margin	**40.2%**	**55.7%**	**75.2%**	**109.5%**	**65.0%**	**28.4%**	**16.6%**	**18.7%**	**35.2%**	**57.8%**	**40.2%**	**38.1%**

	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Peak-Hour (50th+15.5%) w/EE	(3,254)	(2,974)	(2,761)	(2,576)	(3,337)	(4,626)	(4,816)	(4,568)	(3,784)	(2,871)	(2,946)	(3,205)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,254)**	**(2,974)**	**(2,761)**	**(2,576)**	**(3,337)**	**(4,451)**	**(4,640)**	**(4,440)**	**(3,681)**	**(2,871)**	**(2,946)**	**(3,205)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	353	362	285	430	463	442	294	253	243	217	199	374
Total Hydroelectric (50%)	**1,366**	**1,374**	**1,345**	**1,490**	**1,620**	**1,598**	**1,354**	**1,265**	**1,159**	**1,085**	**874**	**1,338**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	92	92	92	92	92	91	91	91	92	92	92	92
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**123**	**131**	**238**	**274**	**313**	**423**	**420**	**412**	**295**	**258**	**226**	**124**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**43**	**63**	**56**	**61**	**46**	**51**	**56**	**37**
Available Transmission w/3rd Party Secured	**131**	**188**	**249**	**258**	**164**	**380**	**373**	**380**	**380**	**276**	**168**	**100**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,399**	**3,465**	**3,603**	**3,782**	**3,841**	**4,134**	**3,867**	**3,784**	**3,579**	**3,390**	**3,059**	**3,353**
Monthly Surplus/Deficit	**145**	**491**	**842**	**1,206**	**504**	**(317)**	**(773)**	**(657)**	**(102)**	**519**	**113**	**148**
2021 IRP Resources												
New Transmission—B2H	400	400	400	695	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	81	81	81	81	162	162	162	162	162	81	81	81
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	5	5	5	10	10	10	5	5	5	–
New Resource—Solar + Storage 1:1 (Storage)	43	43	43	43	87	87	87	87	87	43	43	43
New Resource—Solar	–	–	34	34	34	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)	(497)
New Resource Subtotal	439	439	478	774	903	768	768	764	717	485	485	439
Monthly Surplus/Deficit	**584**	**930**	**1,320**	**1,980**	**1,406**	**451**	**(4)**	**108**	**615**	**1,004**	**597**	**587**
Planning Margin	**36.2%**	**51.6%**	**70.7%**	**104.3%**	**64.2%**	**26.8%**	**15.4%**	**18.2%**	**34.3%**	**55.9%**	**38.9%**	**36.7%**

	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Peak-Hour (50th+15.5%) w/EE	(3,292)	(3,000)	(2,779)	(2,584)	(3,352)	(4,681)	(4,859)	(4,621)	(3,807)	(2,881)	(2,956)	(3,225)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,292)**	**(3,000)**	**(2,779)**	**(2,584)**	**(3,352)**	**(4,505)**	**(4,684)**	**(4,493)**	**(3,704)**	**(2,881)**	**(2,956)**	**(3,225)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	352	361	283	429	459	441	294	253	243	217	199	371
Total Hydroelectric (50%)	**1,365**	**1,373**	**1,344**	**1,490**	**1,616**	**1,598**	**1,354**	**1,265**	**1,158**	**1,085**	**874**	**1,335**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	87	87	87	86	86	85	85	85	86	86	86	86
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**118**	**127**	**233**	**268**	**308**	**418**	**414**	**406**	**289**	**252**	**220**	**118**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**43**	**63**	**56**	**61**	**46**	**51**	**56**	**37**
Available Transmission w/3rd Party Secured	**130**	**185**	**249**	**257**	**163**	**380**	**372**	**380**	**380**	**275**	**167**	**99**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,393**	**3,456**	**3,597**	**3,774**	**3,830**	**4,127**	**3,861**	**3,778**	**3,572**	**3,383**	**3,052**	**3,343**
Monthly Surplus/Deficit	**101**	**457**	**818**	**1,190**	**479**	**(378)**	**(823)**	**(716)**	**(131)**	**503**	**96**	**118**
2021 IRP Resources												
New Transmission—B2H	400	400	400	692	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	149	149	149	149	298	298	298	298	298	149	149	149
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—Solar + Storage 1:1 (Storage)	87	87	87	87	174	174	174	174	174	87	87	87
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	385	385	435	727	971	835	835	831	779	435	435	385
Monthly Surplus/Deficit	**486**	**842**	**1,253**	**1,917**	**1,449**	**457**	**12**	**116**	**648**	**938**	**531**	**503**
Planning Margin	**32.6%**	**47.9%**	**67.6%**	**101.2%**	**65.5%**	**26.8%**	**15.8%**	**18.4%**	**35.2%**	**53.1%**	**36.3%**	**33.5%**

	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Peak-Hour (50th+15.5%) w/EE	(3,316)	(3,018)	(2,790)	(2,594)	(3,368)	(4,722)	(4,904)	(4,669)	(3,832)	(2,892)	(2,968)	(3,238)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,316)**	**(3,018)**	**(2,790)**	**(2,594)**	**(3,368)**	**(4,546)**	**(4,729)**	**(4,541)**	**(3,729)**	**(2,892)**	**(2,968)**	**(3,238)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	351	359	282	429	458	438	294	252	242	217	199	368
Total Hydroelectric (50%)	**1,364**	**1,371**	**1,342**	**1,489**	**1,615**	**1,594**	**1,354**	**1,265**	**1,158**	**1,085**	**874**	**1,332**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	86	86	86	86	86	81	81	81	82	82	82	82
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**117**	**125**	**232**	**268**	**308**	**414**	**410**	**402**	**285**	**248**	**216**	**114**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**43**	**63**	**56**	**61**	**46**	**51**	**56**	**37**
Available Transmission w/3rd Party Secured	**130**	**185**	**248**	**256**	**162**	**380**	**371**	**380**	**380**	**274**	**166**	**99**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,390**	**3,453**	**3,593**	**3,773**	**3,829**	**4,120**	**3,856**	**3,774**	**3,568**	**3,379**	**3,046**	**3,335**
Monthly Surplus/Deficit	**73**	**435**	**803**	**1,180**	**461**	**(427)**	**(873)**	**(768)**	**(160)**	**486**	**79**	**97**
2021 IRP Resources												
New Transmission—B2H	400	400	400	688	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	173	173	173	173	346	346	346	346	346	173	173	173
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—Solar + Storage 1:1 (Storage)	87	87	87	87	174	174	174	174	174	87	87	87
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	409	409	459	748	1,019	883	883	879	827	459	459	409
Monthly Surplus/Deficit	**482**	**844**	**1,262**	**1,927**	**1,480**	**457**	**10**	**111**	**667**	**945**	**538**	**506**
Planning Margin	**32.3%**	**47.8%**	**67.8%**	**101.3%**	**66.3%**	**26.7%**	**15.7%**	**18.3%**	**35.6%**	**53.2%**	**36.4%**	**33.5%**

	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Peak-Hour (50th+15.5%) w/EE	(3,342)	(3,035)	(2,803)	(2,599)	(3,377)	(4,780)	(4,944)	(4,721)	(3,849)	(2,898)	(2,974)	(3,260)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,342)**	**(3,035)**	**(2,803)**	**(2,599)**	**(3,377)**	**(4,604)**	**(4,769)**	**(4,594)**	**(3,746)**	**(2,898)**	**(2,974)**	**(3,260)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	349	360	281	428	457	436	294	252	242	217	199	364
Total Hydroelectric (50%)	**1,362**	**1,372**	**1,342**	**1,489**	**1,614**	**1,592**	**1,354**	**1,265**	**1,158**	**1,084**	**873**	**1,328**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	75	63	63	63	61	60	60	60	61	61	58	58
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**105**	**103**	**210**	**246**	**283**	**393**	**389**	**381**	**264**	**228**	**193**	**90**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**43**	**63**	**56**	**61**	**46**	**51**	**56**	**37**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,376**	**3,430**	**3,569**	**3,750**	**3,802**	**4,097**	**3,833**	**3,753**	**3,547**	**3,357**	**3,022**	**3,307**
Monthly Surplus/Deficit	**34**	**395**	**767**	**1,150**	**425**	**(507)**	**(935)**	**(841)**	**(198)**	**459**	**48**	**47**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	197	197	197	197	394	394	394	394	394	197	197	197
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—Solar + Storage 1:1 (Storage)	87	87	87	87	174	174	174	174	174	87	87	87
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	433	433	483	768	1,067	932	932	928	875	483	483	433
Monthly Surplus/Deficit	**467**	**828**	**1,250**	**1,918**	**1,492**	**425**	**(4)**	**87**	**677**	**942**	**531**	**480**
Planning Margin	**31.6%**	**47.0%**	**67.0%**	**100.7%**	**66.5%**	**25.8%**	**15.4%**	**17.6%**	**35.8%**	**53.1%**	**36.1%**	**32.5%**

	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Peak-Hour (50th+15.5%) w/EE	(3,367)	(3,051)	(2,812)	(2,608)	(3,394)	(4,823)	(4,989)	(4,770)	(3,874)	(2,908)	(2,984)	(3,272)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,367)**	**(3,051)**	**(2,812)**	**(2,608)**	**(3,394)**	**(4,647)**	**(4,813)**	**(4,642)**	**(3,771)**	**(2,908)**	**(2,984)**	**(3,272)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	348	358	280	427	456	434	293	252	242	217	198	360
Total Hydroelectric (50%)	**1,360**	**1,370**	**1,341**	**1,488**	**1,613**	**1,590**	**1,354**	**1,264**	**1,158**	**1,084**	**873**	**1,324**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	58	58	58	58	58	57	57	57	58	58	58	58
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**89**	**98**	**204**	**241**	**280**	**390**	**387**	**378**	**261**	**225**	**192**	**90**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	7	8	8	8	9	9	10	10
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**43**	**63**	**56**	**61**	**46**	**51**	**56**	**37**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,358**	**3,423**	**3,563**	**3,743**	**3,798**	**4,092**	**3,830**	**3,750**	**3,544**	**3,354**	**3,021**	**3,303**
Monthly Surplus/Deficit	**(9)**	**372**	**751**	**1,135**	**405**	**(555)**	**(983)**	**(893)**	**(227)**	**446**	**38**	**31**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	221	221	221	221	442	442	442	442	442	221	221	221
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—Solar + Storage 1:1 (Storage)	87	87	87	87	174	174	174	174	174	87	87	87
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	457	457	507	792	1,115	980	980	976	923	507	507	457
Monthly Surplus/Deficit	**448**	**829**	**1,258**	**1,928**	**1,520**	**425**	**(3)**	**83**	**697**	**953**	**545**	**488**
Planning Margin	**30.9%**	**46.9%**	**67.2%**	**100.9%**	**67.2%**	**25.7%**	**15.4%**	**17.5%**	**36.3%**	**53.4%**	**36.6%**	**32.7%**

	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Peak-Hour (50th+15.5%) w/EE	(3,391)	(3,067)	(2,823)	(2,613)	(3,405)	(4,877)	(5,029)	(4,820)	(3,890)	(2,912)	(2,989)	(3,291)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,391)**	**(3,067)**	**(2,823)**	**(2,613)**	**(3,405)**	**(4,702)**	**(4,854)**	**(4,693)**	**(3,787)**	**(2,912)**	**(2,989)**	**(3,291)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	347	357	279	427	456	432	293	252	242	216	198	356
Total Hydroelectric (50%)	**1,359**	**1,369**	**1,339**	**1,487**	**1,612**	**1,589**	**1,354**	**1,264**	**1,158**	**1,084**	**873**	**1,320**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	38	38	38	38	38	38	38	38	38	38	38	38
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**69**	**78**	**184**	**221**	**260**	**370**	**367**	**359**	**241**	**205**	**172**	**70**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	10	10	9	10	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**35**	**35**	**53**	**51**	**36**	**55**	**48**	**53**	**37**	**42**	**46**	**27**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,337**	**3,402**	**3,541**	**3,723**	**3,771**	**4,063**	**3,803**	**3,722**	**3,515**	**3,324**	**2,991**	**3,269**
Monthly Surplus/Deficit	**(53)**	**335**	**719**	**1,110**	**366**	**(639)**	**(1,051)**	**(971)**	**(272)**	**412**	**2**	**(22)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	265	265	265	265	529	529	529	529	529	265	265	265
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	10	10	10	20	20	20	10	10	10	–
New Resource—Solar + Storage 1:1 (Storage)	87	87	87	87	174	174	174	174	174	87	87	87
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	501	501	551	836	1,203	1,067	1,067	1,063	1,011	551	551	501
Monthly Surplus/Deficit	**447**	**836**	**1,270**	**1,946**	**1,568**	**428**	**16**	**92**	**739**	**963**	**553**	**479**
Planning Margin	**30.7%**	**47.0%**	**67.4%**	**101.5%**	**68.7%**	**25.6%**	**15.9%**	**17.7%**	**37.4%**	**53.7%**	**36.9%**	**32.3%**

	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Peak-Hour (50th+15.5%) w/EE	(3,414)	(3,084)	(2,833)	(2,623)	(3,425)	(4,926)	(5,080)	(4,876)	(3,925)	(2,929)	(3,004)	(3,308)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,414)**	**(3,084)**	**(2,833)**	**(2,623)**	**(3,425)**	**(4,751)**	**(4,905)**	**(4,749)**	**(3,823)**	**(2,929)**	**(3,004)**	**(3,308)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	346	357	277	426	455	431	293	252	242	216	198	352
Total Hydroelectric (50%)	**1,358**	**1,369**	**1,337**	**1,486**	**1,612**	**1,587**	**1,353**	**1,264**	**1,157**	**1,084**	**873**	**1,316**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	38	38	38	38	38	38	38	38	38	38	38	38
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**69**	**78**	**184**	**221**	**260**	**370**	**367**	**359**	**241**	**205**	**172**	**70**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**25**	**25**	**44**	**41**	**36**	**55**	**48**	**53**	**37**	**42**	**46**	**27**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,326**	**3,391**	**3,530**	**3,712**	**3,770**	**4,062**	**3,802**	**3,721**	**3,515**	**3,324**	**2,991**	**3,264**
Monthly Surplus/Deficit	**(88)**	**307**	**697**	**1,089**	**345**	**(689)**	**(1,102)**	**(1,027)**	**(308)**	**395**	**(14)**	**(43)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	287	287	287	287	573	573	573	573	573	287	287	287
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	15	15	15	31	31	31	15	15	15	–
New Resource—Solar + Storage 1:1 (Storage)	130	130	130	130	260	260	260	260	260	130	130	130
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	334	334	334	334	334	334	334	334	334	334	334	334
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	566	566	621	906	1,338	1,208	1,208	1,204	1,147	621	621	566
Monthly Surplus/Deficit	**478**	**873**	**1,319**	**1,995**	**1,683**	**519**	**106**	**177**	**839**	**1,017**	**608**	**523**
Planning Margin	**31.7%**	**48.2%**	**69.3%**	**103.4%**	**72.2%**	**27.7%**	**17.9%**	**19.7%**	**40.2%**	**55.6%**	**38.9%**	**33.8%**

	1/2035	2/2035	3/2035	4/2035	5/2035	6/2035	7/2035	8/2035	9/2035	10/2035	11/2035	12/2035
Peak-Hour (50th+15.5%) w/EE	(3,441)	(3,105)	(2,848)	(2,636)	(3,449)	(4,979)	(5,133)	(4,933)	(3,959)	(2,944)	(3,018)	(3,326)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,441)**	**(3,105)**	**(2,848)**	**(2,636)**	**(3,449)**	**(4,804)**	**(4,957)**	**(4,806)**	**(3,856)**	**(2,944)**	**(3,018)**	**(3,326)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	345	354	275	425	454	431	293	251	242	216	196	348
Total Hydroelectric (50%)	**1,357**	**1,367**	**1,335**	**1,485**	**1,611**	**1,588**	**1,353**	**1,263**	**1,157**	**1,083**	**871**	**1,312**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	38	38	38	38	38	38	38	38	38	38	38	38
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**69**	**78**	**184**	**221**	**260**	**370**	**367**	**359**	**241**	**205**	**172**	**70**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**25**	**25**	**44**	**41**	**36**	**55**	**48**	**53**	**37**	**42**	**46**	**27**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,325**	**3,389**	**3,529**	**3,711**	**3,769**	**4,062**	**3,802**	**3,721**	**3,515**	**3,324**	**2,989**	**3,260**
Monthly Surplus/Deficit	**(116)**	**284**	**681**	**1,075**	**320**	**(742)**	**(1,155)**	**(1,085)**	**(341)**	**379**	**(29)**	**(66)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	376	376	376	376	753	753	753	753	753	376	376	376
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Solar + Storage 1:1 (Solar)	–	–	20	20	20	41	41	41	20	20	20	–
New Resource—Solar + Storage 1:1 (Storage)	174	174	174	174	347	347	347	347	347	174	174	174
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	365	365	425	710	1,275	1,150	1,150	1,146	1,084	425	425	365
Monthly Surplus/Deficit	**249**	**649**	**1,106**	**1,785**	**1,595**	**408**	**(5)**	**61**	**742**	**805**	**396**	**299**
Planning Margin	**23.8%**	**39.7%**	**60.4%**	**93.7%**	**68.9%**	**25.0%**	**15.4%**	**16.9%**	**37.2%**	**47.1%**	**30.7%**	**25.9%**

	1/2036	2/2036	3/2036	4/2036	5/2036	6/2036	7/2036	8/2036	9/2036	10/2036	11/2036	12/2036
Peak-Hour (50th+15.5%) w/EE	(3,472)	(3,129)	(2,865)	(2,649)	(3,474)	(5,041)	(5,187)	(4,996)	(3,996)	(2,961)	(3,033)	(3,350)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,472)**	**(3,129)**	**(2,865)**	**(2,649)**	**(3,474)**	**(4,866)**	**(5,011)**	**(4,869)**	**(3,893)**	**(2,961)**	**(3,033)**	**(3,350)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	344	352	274	424	453	429	292	251	241	216	197	342
Total Hydroelectric (50%)	**1,356**	**1,364**	**1,334**	**1,485**	**1,610**	**1,586**	**1,353**	**1,263**	**1,157**	**1,083**	**871**	**1,306**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	38	38	38	38	38	38	38	38	38	38	38	38
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**69**	**78**	**184**	**221**	**260**	**370**	**367**	**359**	**241**	**205**	**172**	**70**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	27
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**25**	**25**	**44**	**41**	**36**	**55**	**48**	**53**	**37**	**42**	**46**	**27**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,324**	**3,387**	**3,528**	**3,710**	**3,768**	**4,060**	**3,802**	**3,721**	**3,514**	**3,324**	**2,989**	**3,255**
Monthly Surplus/Deficit	**(148)**	**257**	**663**	**1,061**	**293**	**(805)**	**(1,210)**	**(1,148)**	**(379)**	**363**	**(44)**	**(95)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	378	378	378	378	757	757	757	757	757	378	378	378
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	49	49	49	49	49	49	49	49	49	49	49	49
New Resource—Solar + Storage 1:1 (Solar)	–	–	20	20	20	41	41	41	20	20	20	–
New Resource—Solar + Storage 1:1 (Storage)	174	174	174	174	347	347	347	347	347	174	174	174
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	415	415	476	761	1,328	1,203	1,203	1,199	1,136	476	476	415
Monthly Surplus/Deficit	**268**	**673**	**1,139**	**1,822**	**1,621**	**398**	**(7)**	**51**	**757**	**839**	**432**	**321**
Planning Margin	**24.4%**	**40.3%**	**61.4%**	**94.9%**	**69.4%**	**24.6%**	**15.3%**	**16.7%**	**37.4%**	**48.2%**	**32.0%**	**26.6%**

	1/2037	2/2037	3/2037	4/2037	5/2037	6/2037	7/2037	8/2037	9/2037	10/2037	11/2037	12/2037
Peak-Hour (50th+15.5%) w/EE	(3,506)	(3,153)	(2,884)	(2,664)	(3,504)	(5,108)	(5,244)	(5,065)	(4,040)	(2,981)	(3,051)	(3,377)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,506)**	**(3,153)**	**(2,884)**	**(2,664)**	**(3,504)**	**(4,933)**	**(5,069)**	**(4,937)**	**(3,937)**	**(2,981)**	**(3,051)**	**(3,377)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	343	350	272	423	452	426	292	251	241	216	196	338
Total Hydroelectric (50%)	**1,355**	**1,363**	**1,332**	**1,483**	**1,609**	**1,583**	**1,353**	**1,263**	**1,157**	**1,083**	**871**	**1,302**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	29	29	29	24	24	23	23	23	24	24	24	24
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**60**	**69**	**175**	**206**	**245**	**356**	**352**	**344**	**226**	**190**	**158**	**55**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	25	25	24	21	16	15	8	13	17	22	26	–
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**25**	**25**	**44**	**41**	**36**	**55**	**48**	**53**	**37**	**42**	**46**	**0**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,314**	**3,376**	**3,517**	**3,694**	**3,752**	**4,043**	**3,787**	**3,706**	**3,500**	**3,309**	**2,974**	**3,209**
Monthly Surplus/Deficit	**(192)**	**223**	**633**	**1,030**	**248**	**(890)**	**(1,282)**	**(1,231)**	**(437)**	**328**	**(76)**	**(168)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	14	14	10	8	–	–	–
New Resource—Battery: 4 hour	424	424	424	424	849	849	849	849	849	424	424	424
New Resource—Battery: 4 hour - Removals	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—Battery: 8 hour	49	49	49	49	49	49	49	49	49	49	49	49
New Resource—Solar + Storage 1:1 (Solar)	–	–	20	20	20	41	41	41	20	20	20	–
New Resource—Solar + Storage 1:1 (Storage)	174	174	174	174	347	347	347	347	347	174	174	174
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	461	461	522	807	1,420	1,295	1,295	1,291	1,228	522	522	461
Monthly Surplus/Deficit	**270**	**684**	**1,155**	**1,837**	**1,668**	**404**	**13**	**60**	**791**	**850**	**446**	**293**
Planning Margin	**24.4%**	**40.6%**	**61.8%**	**95.1%**	**70.5%**	**24.6%**	**15.8%**	**16.9%**	**38.1%**	**48.4%**	**32.4%**	**25.5%**

	1/2038	2/2038	3/2038	4/2038	5/2038	6/2038	7/2038	8/2038	9/2038	10/2038	11/2038	12/2038
Peak-Hour (50th+15.5%) w/EE	(3,541)	(3,180)	(2,903)	(2,681)	(3,536)	(5,171)	(5,304)	(5,132)	(4,087)	(3,003)	(3,071)	(3,400)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,541)**	**(3,180)**	**(2,903)**	**(2,681)**	**(3,536)**	**(4,996)**	**(5,129)**	**(5,005)**	**(3,984)**	**(3,003)**	**(3,071)**	**(3,400)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	342	351	271	422	451	425	292	251	241	215	197	333
Total Hydroelectric (50%)	**1,354**	**1,363**	**1,331**	**1,483**	**1,607**	**1,582**	**1,352**	**1,263**	**1,157**	**1,083**	**872**	**1,297**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	24	24	24	24	24	23	23	23	24	24	24	24
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**54**	**63**	**170**	**206**	**245**	**356**	**352**	**344**	**226**	**190**	**158**	**55**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**0**	**0**	**20**	**20**	**20**	**40**	**40**	**40**	**20**	**20**	**20**	**0**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,282**	**3,346**	**3,486**	**3,673**	**3,735**	**4,026**	**3,780**	**3,693**	**3,482**	**3,287**	**2,949**	**3,204**
Monthly Surplus/Deficit	**(258)**	**166**	**583**	**991**	**199**	**(970)**	**(1,349)**	**(1,312)**	**(501)**	**283**	**(122)**	**(196)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	–	–	–	–	–	–	–	–	–	–	–	–
New Resource—DR	–	–	–	–	–	22	22	16	13	–	–	–
New Resource—Battery: 4 hour	427	427	427	427	853	853	853	853	853	427	427	427
New Resource—Battery: 4 hour - Removals	(50)	(50)	(50)	(50)	(101)	(101)	(101)	(101)	(101)	(50)	(50)	(50)
New Resource—Battery: 8 hour	97	97	97	97	97	97	97	97	97	97	97	97
New Resource—Solar + Storage 1:1 (Solar)	–	–	26	26	26	51	51	51	26	26	26	–
New Resource—Solar + Storage 1:1 (Storage)	217	217	217	217	434	434	434	434	434	217	217	217
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	505	505	571	856	1,464	1,351	1,351	1,345	1,277	571	571	505
Monthly Surplus/Deficit	**247**	**671**	**1,153**	**1,847**	**1,663**	**382**	**2**	**34**	**775**	**854**	**449**	**309**
Planning Margin	**23.6%**	**39.9%**	**61.4%**	**95.1%**	**69.8%**	**24.0%**	**15.5%**	**16.3%**	**37.4%**	**48.3%**	**32.4%**	**26.0%**

	1/2039	2/2039	3/2039	4/2039	5/2039	6/2039	7/2039	8/2039	9/2039	10/2039	11/2039	12/2039
Peak-Hour (50th+15.5%) w/EE	(3,573)	(3,204)	(2,921)	(2,695)	(3,565)	(5,237)	(5,361)	(5,198)	(4,128)	(3,021)	(3,086)	(3,426)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,573)**	**(3,204)**	**(2,921)**	**(2,695)**	**(3,565)**	**(5,061)**	**(5,185)**	**(5,071)**	**(4,025)**	**(3,021)**	**(3,086)**	**(3,426)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	342	351	271	422	451	425	292	251	241	215	197	333
Total Hydroelectric (50%)	**1,354**	**1,363**	**1,331**	**1,483**	**1,607**	**1,582**	**1,352**	**1,263**	**1,157**	**1,083**	**872**	**1,297**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	24	24	24	24	24	23	23	23	24	24	24	24
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**54**	**63**	**170**	**206**	**245**	**356**	**352**	**344**	**226**	**190**	**158**	**55**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**0**	**0**	**20**	**20**	**20**	**40**	**40**	**40**	**20**	**20**	**20**	**0**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,282**	**3,346**	**3,486**	**3,673**	**3,735**	**4,026**	**3,780**	**3,693**	**3,482**	**3,287**	**2,949**	**3,204**
Monthly Surplus/Deficit	**(290)**	**142**	**565**	**977**	**170**	**(1,035)**	**(1,406)**	**(1,378)**	**(543)**	**266**	**(138)**	**(222)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	2	2	2	2	2	2	2	2	2	2	2	2
New Resource—DR	–	–	–	–	–	29	29	21	17	–	–	–
New Resource—Battery: 4 hour	451	451	451	451	901	901	901	901	901	451	451	451
New Resource—Battery: 4 hour - Removals	(53)	(53)	(53)	(53)	(105)	(105)	(105)	(105)	(105)	(53)	(53)	(53)
New Resource—Battery: 8 hour	97	97	97	97	97	97	97	97	97	97	97	97
New Resource—Solar + Storage 1:1 (Solar)	–	–	26	26	26	51	51	51	26	26	26	–
New Resource—Solar + Storage 1:1 (Storage)	217	217	217	217	434	434	434	434	434	217	217	217
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	529	529	595	880	1,510	1,404	1,404	1,396	1,327	595	595	529
Monthly Surplus/Deficit	**239**	**671**	**1,160**	**1,857**	**1,680**	**370**	**(2)**	**18**	**784**	**860**	**457**	**307**
Planning Margin	**23.2%**	**39.7%**	**61.4%**	**95.1%**	**69.9%**	**23.7%**	**15.5%**	**15.9%**	**37.4%**	**48.4%**	**32.6%**	**25.8%**

	1/2040	2/2040	3/2040	4/2040	5/2040	6/2040	7/2040	8/2040	9/2040	10/2040	11/2040	12/2040
Peak-Hour (50th+15.5%) w/EE	(3,610)	(3,232)	(2,942)	(2,712)	(3,597)	(5,306)	(5,421)	(5,269)	(4,175)	(3,043)	(3,106)	(3,453)
Existing Demand Response Capacity	–	–	–	–	–	176	176	127	103	–	–	–
Peak-Hour (50th+15.5%) w/DR and EE	**(3,610)**	**(3,232)**	**(2,942)**	**(2,712)**	**(3,597)**	**(5,130)**	**(5,246)**	**(5,142)**	**(4,072)**	**(3,043)**	**(3,106)**	**(3,453)**
Existing Resources												
Bridger	663	663	663	663	663	663	663	663	663	663	663	663
Valmy	–	–	–	–	–	–	–	–	–	–	–	–
Total Coal	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**663**
Langley Gulch	323	318	315	315	312	306	306	306	309	312	318	323
Total Gas Peakers	429	426	410	400	396	370	365	367	397	415	424	437
Total Gas	**752**	**743**	**725**	**715**	**708**	**675**	**671**	**672**	**706**	**727**	**741**	**761**
Hydro (50%) HCC	1,012	1,012	1,060	1,060	1,157	1,157	1,060	1,012	916	868	675	964
Hydro (50%)—Other	342	351	271	422	451	425	292	251	241	215	197	333
Total Hydroelectric (50%)	**1,354**	**1,363**	**1,331**	**1,483**	**1,607**	**1,582**	**1,352**	**1,263**	**1,157**	**1,083**	**872**	**1,297**
Solar CSPP (PURPA)	–	–	99	99	99	199	199	199	99	99	99	–
Wind CSPP Capacity	24	24	24	24	24	23	23	23	24	24	24	24
Other CSPP	31	39	47	83	122	134	130	122	104	67	35	32
Total CSPP	**54**	**63**	**170**	**206**	**245**	**356**	**352**	**344**	**226**	**190**	**158**	**55**
Elkhorn	–	–	–	–	–	–	–	–	–	–	–	–
Raft River Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Neal Hot Springs Geothermal	–	–	–	–	–	–	–	–	–	–	–	–
Jackpot Solar	–	–	20	20	20	40	40	40	20	20	20	–
Clatskanie Exchange	–	–	–	–	–	–	–	–	–	–	–	–
Total PPAs	**0**	**0**	**20**	**20**	**20**	**40**	**40**	**40**	**20**	**20**	**20**	**0**
Available Transmission w/3rd Party Secured	**129**	**184**	**247**	**256**	**161**	**380**	**370**	**380**	**380**	**274**	**165**	**98**
Emergency Transmission (CBM)	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**	**330**
Existing Resource Subtotal	**3,282**	**3,346**	**3,486**	**3,673**	**3,735**	**4,026**	**3,780**	**3,693**	**3,482**	**3,287**	**2,949**	**3,204**
Monthly Surplus/Deficit	**(328)**	**114**	**545**	**961**	**138**	**(1,104)**	**(1,466)**	**(1,449)**	**(590)**	**244**	**(157)**	**(249)**
2021 IRP Resources												
New Transmission—B2H	400	400	400	685	700	500	500	500	500	400	400	400
New Resource—EE	5	5	5	5	5	5	5	5	5	5	5	5
New Resource—DR	–	–	–	–	–	36	36	26	21	–	–	–
New Resource—Battery: 4 hour	475	475	475	475	949	949	949	949	949	475	475	475
New Resource—Battery: 4 hour - Removals	(55)	(55)	(55)	(55)	(109)	(109)	(109)	(109)	(109)	(55)	(55)	(55)
New Resource—Battery: 8 hour	97	97	97	97	97	97	97	97	97	97	97	97
New Resource—Solar + Storage 1:1 (Solar)	–	–	26	26	26	51	51	51	26	26	26	–
New Resource—Solar + Storage 1:1 (Storage)	217	217	217	217	434	434	434	434	434	217	217	217
New Resource—Solar	–	–	40	40	40	80	80	80	40	40	40	–
New Resource—WY Wind	45	45	45	45	45	45	45	45	45	45	45	45
New Resource—ID Wind	33	33	33	33	33	33	33	33	33	33	33	33
New Resource—Gas Conversion (exit 2034)	–	–	–	–	–	–	–	–	–	–	–	–
Early Bridger Coal Exits	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)	(663)
New Resource Subtotal	554	554	620	905	1,557	1,458	1,458	1,449	1,378	620	620	554
Monthly Surplus/Deficit	**227**	**669**	**1,164**	**1,866**	**1,695**	**355**	**(8)**	**(0)**	**789**	**864**	**463**	**305**
Planning Margin	**22.8%**	**39.4%**	**61.2%**	**95.0%**	**69.9%**	**23.2%**	**15.3%**	**15.5%**	**37.3%**	**48.3%**	**32.7%**	**25.7%**

DEMAND-SIDE RESOURCE DATA

DSM Financial Assumptions

Avoided Levelized Capacity Costs	
Simple Cycle Combustion Turbine (SCCT)	$131.60/kW-year*
Financial Assumptions	
Discount rate (weighted average cost of capital)	7.12%
Financial escalation factor	2.30%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

*The selection of an SCCT matches the company's filings for approval to modify its demand response programs (IPUC Case No. IPC-E-21-32 and OPUC Tariff Advice No. 21-12). An SCCT is also the resource selected to fulfill unmet LOLE reliability requirements in the 2021 IRP.

Avoided Cost Averages ($/MWh except where noted)

Year	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	Non-Summer Mid-Peak	Non-Summer Off-Peak	Annual T&D On-Peak EE Deferral Value ($/kW-year)
2021	$32.43	$26.86	$23.33	$26.96	$23.92	$6.33
2022	$32.83	$26.70	$23.62	$26.41	$23.64	$6.42
2023	$47.75	$40.76	$35.04	$36.78	$33.10	$6.42
2024	$49.14	$41.34	$36.00	$36.46	$33.57	$6.77
2025	$49.63	$41.03	$36.28	$34.61	$32.32	$6.35
2026	$50.40	$40.01	$34.38	$35.11	$32.97	$6.39
2027	$50.75	$35.14	$31.16	$30.71	$31.06	$6.35
2028	$54.17	$36.81	$32.71	$31.79	$33.55	$6.53
2029	$53.51	$36.42	$33.44	$33.05	$35.85	$6.64
2030	$51.51	$30.48	$30.30	$30.44	$36.23	$6.44
2031	$54.93	$31.80	$32.57	$31.69	$37.22	$6.35
2032	$55.88	$32.56	$33.72	$33.05	$39.16	$6.33
2033	$55.06	$29.37	$33.17	$31.75	$40.52	$6.52
2034	$57.35	$31.20	$34.77	$32.64	$41.68	$6.29
2035	$57.24	$31.79	$35.03	$34.11	$43.54	$3.89
2036	$58.88	$32.54	$36.79	$36.38	$44.18	$2.53
2037	$56.64	$29.74	$35.62	$30.80	$39.90	$2.54
2038	$58.93	$32.09	$38.00	$32.12	$42.51	$1.53
2039	$61.82	$34.40	$40.23	$32.53	$42.10	$1.65
2040	$62.84	$35.36	$41.54	$32.02	$42.16	$1.72

*Energy efficiency will also receive a capacity value in all Summer On-Peak hours when the company is capacity deficient, and the measure contributes energy savings during those hours.

DSM alternate cost summer pricing periods (June 1–August 31)

Hour End	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
2	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
3	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
4	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
5	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
6	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
7	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
8	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
9	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
10	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
11	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
12	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SOFP
13	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SOFP
14	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SOFP
15	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SOFP
16	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
17	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
18	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
19	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
20	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
21	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
22	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
23	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SOFP
24	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SOFP

SOFP—Summer Off-Peak
SMP—Summer Mid-Peak
SONP—Summer On-Peak

DSM alternate cost non-summer pricing periods (September 1–May 31)

Hour End	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
2	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
3	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
4	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
5	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
6	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
7	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
8	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
9	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
10	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
11	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
12	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
13	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
14	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
15	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
16	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
17	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
18	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
19	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
20	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
21	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
22	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
23	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
24	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP

NSOFP—Non-Summer Off-Peak

NSMP—Non-Summer Mid-Peak

Bundle Amounts

Incremental Achievable Potential (aMW)

Bundle	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Summer Low	3	3	3	3	4	4	4	5	4	4
Summer High	5	8	12	16	20	23	24	26	27	28
Winter Low	6	8	11	15	18	21	21	21	21	19
Winter High	3	3	4	4	5	6	6	7	7	7
Total	**17**	**21**	**30**	**38**	**47**	**53**	**56**	**58**	**59**	**59**

Bundle	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Summer Low	4	4	4	4	3	3	3	3	3	3
Summer High	28	28	28	28	27	25	22	22	20	18
Winter Low	17	14	11	10	8	8	6	6	6	6
Winter High	8	7	7	7	7	6	6	6	6	5
Total	**57**	**54**	**50**	**48**	**45**	**42**	**37**	**37**	**35**	**32**

Bundle Costs

Savings Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Summer Low	$80	$90	$97	$99	$101	$104	$107	$108	$109	$108
Summer High	$1,699	$1,305	$1,040	$861	$789	$721	$654	$606	$570	$544
Winter Low	$70	$70	$69	$69	$69	$69	$68	$67	$66	$66
Winter High	$249	$331	$349	$359	$368	$368	$360	$352	$346	$320
Total	**$552**	**$523**	**$465**	**$416**	**$386**	**$359**	**$330**	**$308**	**$297**	**$287**

Bundle	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Summer Low	$107	$105	$105	$104	$104	$104	$105	$105	$105	$105
Summer High	$527	$515	$506	$497	$494	$476	$461	$458	$460	$463
Winter Low	$66	$66	$65	$65	$65	$64	$60	$60	$59	$60
Winter High	$321	$324	$328	$321	$313	$302	$290	$305	$293	$285
Total	**$291**	**$299**	**$306**	**$308**	**$309**	**$298**	**$288**	**$294**	**$284**	**$276**

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%
General O&M escalation rate	2.30%
Annual property tax rate (% of investment)	0.47%
B2H annual property tax rate (% of investment)	0.64%
Property tax escalation rate	3.00%
B2H property tax escalation rate	0.68%
Annual insurance premiums (% of investment)	0.049%
B2H annual insurance premiums (% of investment)	0.004%
Insurance escalation rate	3.00%
B2H insurance escalation rate	3.00%
AFUDC rate (annual)	7.45%

[1] Incorporates tax effects.

Cost Inputs and Operating Assumptions (Costs in 2021$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital[1] ($/kW)	Transmission/Interconnection Capital ($/kW)	Total Capital ($/kW)	Fixed O&M[2] ($/kW-mth)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Economic Life[3] (years)
Aeroderivative (45 MW)	45	$1,500	$166	$1,666	$1.42	$4.92	8,533	40
Biomass (35 MW)	35	$4,176	$128	$4,304	$3.54	$4.71	0	30
Boardman to Hemingway (500 MW Summer/200 MW Winter)		$0	$647	$647	$0.03	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,656	$25	$1,681	$1.49	$1.11	6,708	30
Danskin 1 Retrofit (90 MW)	90	$2,350	$41	$2,391	$1.49	$1.11	6,909	30
Geothermal (30 MW)	30	$4,500	$149	$4,649	$11.99	$0.00	0	30
Reciprocating Gas Engine (55.5 MW)	56	$1,560	$67	$1,627	$3.07	$5.95	8,300	40
SCCT—Frame F Class (170 MW)	170	$900	$22	$922	$1.02	$4.82	9,720	35
Small Modular Nuclear (77 MW)	77	$4,250	$144	$4,394	$10.62	$2.48	11,500	60
Solar PV—Utility Scale 1-Axis Tracking (100 MW)	100	$1,000	$50	$1050	$0.81	$0.00	0	30
Solar PV—Utility Scale 1-Axis Tracking (100 MW) w/ 4-hr Battery (100 MW)	100	$2,150	$50	$2,200	$3.30	$0.00	0	30[3]
Storage—4-Hour Li Battery (50 MW)	50	$1,150	$77	$1,227	$2.49	$0.00	0	15
Storage—4-Hour Li Battery for Grid Benefits (5 MW)	5	$863	$77	$940	$2.49	$0.00	0	15
Storage—8-Hour Li Battery (50 MW)	50	$2,100	$77	$2,177	$2.49	$0.00	0	15
Storage—Compressed Air Energy Storage (150 MW)	150	$2,200	$77	$2,277	$1.08	$6.65	0	50
Storage—Pumped-Hydro (250 MW)	250	$2,100	$227	$2,327	$0.38	$0.00	0	75
SWIP North (100 MW Summer/200 MW Winter)		$0	$798	$798	$0.04	$0.00	0	55
Wind ID (100 MW)	100	$1,300	$50	$1,350	$2.11	$0.00	0	25
Wind WY (100 MW)	100	$1,300	$50	$1,350	$2.11	$0.00	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] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)
[3] Economic life assumed for the solar component is 30 years and is 15 years for the storage component

Supply-Side Resource Escalation Factors[1] (2022–2030)

Supply-Side Resources	2022	2023	2024	2025	2026	2027	2028	2029	2030
Aeroderivative (45 MW)	1.81%	1.12%	0.46%	1.06%	1.55%	1.48%	1.76%	1.93%	1.79%
Biomass (35 MW)	2.17%	2.17%	2.17%	1.93%	2.12%	2.06%	2.10%	2.08%	1.98%
CCCT (1x1) F Class (300 MW)	1.21%	1.20%	0.89%	1.28%	1.69%	1.63%	1.85%	1.97%	1.83%
Danskin 1 Retrofit (90 MW)	1.21%	1.20%	0.89%	1.28%	1.69%	1.63%	1.85%	1.97%	1.83%
Geothermal (30 MW)	0.14%	0.09%	0.04%	-0.01%	-0.06%	-0.12%	-0.17%	-0.24%	-0.29%
Reciprocating Gas Engine (55.5 MW)	1.81%	1.12%	0.46%	1.06%	1.55%	1.48%	1.76%	1.93%	1.79%
SCCT—Frame F Class (170 MW)	1.81%	1.12%	0.46%	1.06%	1.55%	1.48%	1.76%	1.93%	1.79%
Small Modular Nuclear (77 MW)	-2.15%	-2.15%	-2.15%	-2.15%	-2.15%	-2.15%	-2.15%	-2.15%	-2.15%
Solar PV—Utility Scale 1-Axis Tracking (100 MW)	-1.76%	-1.93%	-2.11%	-2.31%	-2.53%	-2.77%	-3.04%	-3.33%	-3.66%
Solar PV—Utility Scale 1-Axis Tracking (100 MW) w/ 4-hr Battery (100 MW)	-3.60%	-4.01%	-4.47%	-5.02%	-2.90%	-3.18%	-3.49%	-3.84%	-4.23%
Storage—4-Hour Li Battery (50 MW)	-5.45%	-6.08%	-6.83%	-7.72%	-3.26%	-3.58%	-3.94%	-4.35%	-4.81%
Storage—4-Hour Li Battery for Grid Benefits (5 MW)	-5.45%	-6.08%	-6.83%	-7.72%	-3.26%	-3.58%	-3.94%	-4.35%	-4.81%
Storage—8-Hour Li Battery (50 MW)	-5.45%	-6.08%	-6.83%	-7.72%	-3.26%	-3.58%	-3.94%	-4.35%	-4.81%
Storage—Compressed Air Energy Storage (150 MW)	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Storage—Pumped-Hydro (250 MW)	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Wind ID (100 MW)	0.22%	0.14%	0.06%	-0.03%	-0.12%	-0.21%	-0.32%	-0.43%	-0.54%
Wind WY (100 MW)	0.38%	0.27%	0.15%	0.02%	-0.11%	-0.25%	-0.40%	-0.56%	-0.73%

[1] Factors include the 2021 IRP general O&M escalation rate assumption of 2.3%.

Supply-Side Resource Escalation Factors[1] (2031–2040)

Supply-Side Resources	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Aeroderivative (45 MW)	1.86%	1.83%	1.76%	1.91%	2.02%	1.91%	2.06%	2.02%	1.94%	1.92%
Biomass (35 MW)	2.01%	1.98%	1.96%	2.06%	2.03%	1.90%	2.04%	2.00%	1.93%	1.91%
CCCT (1x1) F Class (300 MW)	1.89%	1.86%	1.80%	1.94%	2.01%	1.90%	2.05%	2.01%	1.93%	1.91%
Danskin 1 Retrofit (90 MW)	1.89%	1.86%	1.80%	1.94%	2.01%	1.90%	2.05%	2.01%	1.93%	1.91%
Geothermal (30 MW)	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%
Reciprocating Gas Engine (55.5 MW)	1.86%	1.83%	1.76%	1.91%	2.02%	1.91%	2.06%	2.02%	1.94%	1.92%
SCCT—Frame F Class (170 MW)	1.86%	1.83%	1.76%	1.91%	2.02%	1.91%	2.06%	2.02%	1.94%	1.92%
Small Modular Nuclear (77 MW)	1.62%	1.58%	1.56%	1.67%	1.63%	1.49%	1.63%	1.59%	1.50%	1.48%
Solar PV—Utility Scale 1-Axis Tracking (100 MW)	1.39%	1.38%	1.37%	1.37%	1.36%	1.35%	1.34%	1.33%	1.32%	1.31%
Solar PV—Utility Scale 1-Axis Tracking (100 MW) w/ 4-hr Battery (100 MW)	0.84%	0.82%	0.80%	0.77%	0.74%	0.72%	0.69%	0.66%	0.62%	0.59%
Storage—4-Hour Li Battery (50 MW)	0.30%	0.26%	0.22%	0.17%	0.13%	0.08%	0.03%	-0.02%	-0.07%	-0.13%
Storage—4-Hour Li Battery for Grid Benefits (5 MW)	0.30%	0.26%	0.22%	0.17%	0.13%	0.08%	0.03%	-0.02%	-0.07%	-0.13%
Storage—8-Hour Li Battery (50 MW)	0.30%	0.26%	0.22%	0.17%	0.13%	0.08%	0.03%	-0.02%	-0.07%	-0.13%
Storage—Compressed Air Energy Storage (150 MW)	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Storage—Pumped-Hydro (250 MW)	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Wind ID (100 MW)	1.26%	1.25%	1.24%	1.22%	1.21%	1.19%	1.18%	1.16%	1.15%	1.13%
Wind WY (100 MW)	1.51%	1.50%	1.49%	1.48%	1.47%	1.45%	1.44%	1.43%	1.41%	1.40%

[1] Factors include the 2021 IRP general O&M escalation rate assumption of 2.3%.

Levelized Cost of Energy (costs in 2021$, $/MWh) at stated capacity factors

Supply-Side Resources	Cost of Capital[1]	Non-Fuel O&M[2]	Fuel[3]	Total Cost per MWh[4,5]	Capacity Factor[6]
Aeroderivative (45 MW)	$145	$42	$36	$223	12%
Biomass (35 MW)	$91	$23	$0	$114	61%
Boardman to Hemingway (500 MW Summer/200 MW Winter)	$19	$4	$0	$23	33%
CCCT (1x1) F Class (300 MW)	$38	$9	$26	$73	55%
Danskin 1 Retrofit (90 MW)	$52	$10	$27	$89	55%
Geothermal (30 MW)	$59	$28	$0	$87	95%
Reciprocating Gas Engine (55.5 MW)	$147	$69	$35	$251	12%
SCCT—Frame F Class (170 MW)	$91	$29	$40	$160	12%
Small Modular Nuclear (77 MW)	$62	$32	$9	$103	93%
Solar PV—Utility Scale 1-Axis Tracking (100 MW), 26% ITC	$27	$8	$0	$35	29%
Solar PV—Utility Scale 1-Axis Tracking (100 MW), 10% ITC	$33	$8	$0	$41	29%
Solar PV—Utility Scale 1-Axis Tracking (100 MW) + 4-hr Battery (100 MW), 26% ITC	$65	$23	$0	$88	30%
Solar PV—Utility Scale 1-Axis Tracking (100 MW) + 4-hr Battery (100 MW), 10% ITC	$80	$23	$0	$103	30%
Storage—4-Hour Li Battery (50 MW)	$100	$30	$0	$130	17%
Storage—4-Hour Li Battery for Locational Grid Benefits (5 MW)	$77	$28	$0	$105	17%
Storage—8-Hour Li Battery (50 MW)	$90	$17	$0	$107	33%
Storage—Compressed Air Energy Storage (150 MW)	$73	$23	$0	$96	33%
Storage—Pumped-Hydro (250 MW)	$82	$10	$0	$92	33%
SWIP North (100 MW Summer/200 MW Winter)	$18	$2	$0	$20	33%
Wind ID (100 MW), PTC	$29	$14	$0	$43	35%
Wind ID (100 MW)	$42	$14	$0	$56	35%
Wind WY (100 MW), PTC	$21	$10	$0	$31	48%
Wind WY (100 MW)	$31	$10	$0	$41	48%

[1] Cost of Capital includes tax credit benefits (ITC/PTC).
[2] Non-Fuel O&M includes fixed and variable costs and property taxes.
[3] Fuel costs are not included for biomass resource.
[4] Storage resources will have a cost or benefit associated with the price difference between the energy price to charge the storage and the energy price during the time of discharge (less losses). Arbitrage is not included in the LCOE calculation in the table. As noted in IRP, levelized cost for storage resources is driven by fixed costs.
[5] Transmission resource costs do not include potential benefits of additional short-term and non-firm third-party wheeling usage. The LCOE does not include a price for market purchases, therefore, the LCOE in this table can be viewed as a cost above the market purchase price for the energy assuming the associated capacity factor.
[6] Capacity factor for 4-hour storage resources assume one discharge cycle per day; 8-hour storage resources and above assume eight hours of discharge per day.

Levelized Capacity (fixed) Cost per kW/Month (costs in 2021$)

Supply-Side Resources	Cost of Capital[1]	Non-Fuel O&M[2]	Total Cost per kW
Aeroderivative (45 MW)	$13	$3	$16
Biomass (35 MW)	$40	$8	$48
Boardman to Hemingway (500 MW Summer/200 MW Winter)	$5	$1	$6
CCCT (1x1) F Class (300 MW)	$15	$3	$18
Danskin 1 Retrofit (90 MW)	$21	$3	$24
Geothermal (30 MW)	$41	$19	$60
Reciprocating Gas Engine (55.5 MW)	$13	$5	$18
SCCT—Frame F Class (170 MW)	$8	$2	$10
Small Modular Nuclear (77 MW)	$40	$19	$59
Solar PV—Utility Scale 1-Axis Tracking (100 MW), 26% ITC	$5	$2	$7
Solar PV—Utility Scale 1-Axis Tracking (100 MW), 10% ITC	$7	$2	$9
Solar PV—Utility Scale 1-Axis Tracking (100 MW) + 4-hr Battery (100 MW), 26% ITC	$14	$5	$19
Solar PV—Utility Scale 1-Axis Tracking (100 MW) + 4-hr Battery (100 MW), 10% ITC	$18	$5	$23
Storage—4-Hour Li Battery (50 MW)	$12	$4	$16
Storage—4-Hour Li Battery for Locational Grid Benefits (5 MW)	$9	$4	$13
Storage—8-Hour Li Battery (50 MW)	$22	$4	$26
Storage—Compressed Air Energy Storage (150 MW)	$18	$3	$21
Storage—Pumped-Hydro (250 MW)	$20	$2	$22
SWIP North (100 MW Summer/200 MW Winter)	$4	$1	$5
Wind ID (100 MW), PTC	$8	$4	$12
Wind ID (100 MW)	$10	$4	$14
Wind WY (100 MW), PTC	$7	$4	$11
Wind WY (100 MW)	$10	$4	$14

[1] Cost of Capital includes tax credit benefits (ITC/PTC).

[2] Non-Fuel O&M includes fixed and variable costs, property taxes.

Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2021	7.94
2022	7.82
2023	7.70
2024	7.54
2025	7.37
2026	7.42
2027	7.58
2028	7.58
2029	7.64
2030	7.82
2031	7.85
2032	7.96
2033	8.14
2034	8.20
2035	8.21
2036	8.45
2037	8.46
2038	8.57
2039	8.76
2040	8.87

EXISTING RESOURCE DATA

Qualifying Facility Data (PURPA)

Cogeneration & Small Power Production Projects Status as of December 31, 2020

Hydro Projects

		Contract				Contract	
Project	**MW**	**On-line Date**	**End Date**	**Project**	**MW**	**On-line Date**	**End Date**
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	8.20	May-2020	May-2040
Barber Dam	3.70	Apr-1989	Apr-2024	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Birch Creek	0.07	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-2020	Aug-2040
Box Canyon	0.30	Feb-2019	Feb-2039	MC6 Hydro	2.10	Apr-2021	Estimated
Briggs Creek	0.60	Oct-2020	Oct-2040	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
Coleman Hydro	0.80	Jun-2021	Estimated	North Gooding Main	1.30	Oct-2016	Oct-2036
Crystal Springs	2.44	Apr-1986	Apr-2021	Owyhee Dam CSPP	5.00	Aug-1985	May-2033
Curry Cattle Company	0.25	Jun-2018	Jun-2033	Pigeon Cove	1.75	Oct-1984	Nov-2039
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pristine Springs #1	0.13	May-2020	May-2040
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #3	0.20	May-2020	May-2040
Elk Creek	2.00	May-1986	May-2021	Reynolds Irrigation	0.26	May-1986	May-2021
Fall River	9.10	Aug-1993	Aug-2028	Rock Creek #1	2.17	Jan-2018	Jan-2038
Fargo Drop Hydroelectric	1.27	Apr-2013	Apr-2033	Rock Creek #2	1.90	Apr-1989	Apr-2024
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Sagebrush	0.58	Jun-2021	Jun-2040
Fisheries Dev.	0.26	Jul-1990	Jul-2040	Sahko Hydro	0.50	Feb-2011	Feb-2021
Geo-Bon #2	0.93	Nov-1986	Nov-2021	Schaffner	0.53	Aug-1986	Aug-2021
Hailey CSPP	0.04	Jun-2020	Jun-2025	Shingle Creek	0.22	Aug-2017	Aug-2022
Hazelton A	8.10	Mar-2011	Mar-2026	Shoshone #2	0.58	May-1996	May-2031
Hazelton B	7.60	May-1993	May-2028	Shoshone CSPP	0.36	Feb-2017	Feb-2037
Head of U Canal Project	1.28	May-2015	Jun-2035	Snake River Pottery	0.09	Nov-1984	Dec-2027
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snedigar	0.50	Jan-2020	Jan-2040
Jim Knight	0.48	Jun-2021	Estimated	Tiber Dam	7.50	Jun-2004	Jun-2024
Koyle Small Hydro	1.25	Apr-2019	Apr-2039	Trout-Co	0.24	Dec-1986	Dec-2021
Lateral # 10	2.06	May-2020	May-2040	Tunnel #1	7.00	Jun-1993	Feb-2035
Lemoyne	0.08	Jun-2020	Jun-2030	White Water Ranch	0.16	Aug2020	Aug-2040
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035	Wilson Lake Hydro	8.40	May-1993	May-2028
Little Wood River Res	2.85	Mar-2020	Mar-2040				

Total Hydro Nameplate Rating 150.94 MW

Cogeneration/Thermal Projects

Project	MW	Contract On-line Date	Contract End Date
Pico Energy, LLC	2.13	Aug-2020	Aug-2030
Simplot Pocatello Cogen	15.90	Mar-2019	Mar-2022
TASCO—Nampa Natural Gas	2	Sep-2003	Sept-2040
TASCO—Twin Falls Natural Gas	3	Aug-2001	Jan-2040
Total Thermal Nameplate Rating 23.03 MW			

Biomass Projects

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Bannock County Landfill	3.20	May-2014	May-2034	Pocatello Waste	0.46	Dec-1985	Dec-2020
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029	SISW LFGE	5.00	Sept-2018	Sept-2038
Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027	Tamarack CSPP	6.25	Jun-2018	Jun-2038
Total Biomass Nameplate Rating 21.17 MW							

Solar Projects

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
American Falls Solar II, LLC	20.00	Mar-2017	Mar-2037	Mt. Home Solar 1, LLC	20.00	Mar-2017	Mar-2037
American Falls Solar, LLC	20.00	Mar-2017	Mar-2037	Murphy Flat Power, LLC	20.00	Mar-2017	Mar-2037
Baker Solar Center	15.00	Feb-2020	Feb-2040	Ontario Solar Center	3.00	Mar-2020	Mar-2040
Brush Solar	2.75	Oct-2019	Dec-2039	Open Range Solar Center, LLC	10.00	Mar-2017	Mar-2037
Durkee Solar	3.00	Mar-2022	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	Apr-2020	Apr-2040	Vale 1 Solar	3.00	Jul-2020	Jul-2040
Total Solar Nameplate Rating 319.25 MW							

Wind Projects

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
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 1,141.31 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2020. 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

Project	MW	On-Line Date	Contract End Date
Wind Projects			
Elkhorn Wind Project	101	Dec-2007	Dec-2027
Total Wind Nameplate Rating	**101**		
Geothermal Projects			
Raft River Unit 1	13	Apr-2008	Apr-2033
Neal Hot Springs	22	Nov-2012	Nov-2037
Total Geothermal Nameplate Rating	**35**		
Solar Projects			
Jackpot Solar Facility	120	Dec-2022	Dec-2042
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, 2020. 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.

Hydro Flow Modeling

Hydro Models

Idaho Power uses two modeling methods (planning models) for the development of future hydro flow scenarios for the IRP. The first method accounts for surface water regulation in the system, this consists of two models built in the CADSWES RiverWare modeling framework. The first of these models covers the spatial extent of the Snake River basin from the headwaters to Brownlee inflow. The second model takes the results of the first and regulates the flows through the Hells Canyon Complex (HCC). The second modeling method uses the Enhanced Snake Plain Aquifer Model (ESPAM) to model aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The planning models have been updated to include hydrologic conditions for water years 1951 through 2018. ESPAM was updated with the release of ESPAM 2.1 in late 2012.

Hydro Model Inputs

The inputs for the 2021 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. The modeling also included inputs from other entities diverting ground water on the ESPA who have separate mitigation agreements with the SWC. 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. The modeling also included aquifer recharge efforts by the Idaho Water Resource Board who is targeting an average annual natural flow recharge of 250,000 acre-ft per year.

Recharge capacity modeled for the 2021 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. Total recharge diversions, including private and state sponsored programs, are modeled at approximately 407,000 acre-ft per year of the IRP. In IRP year 2025, approximately 195,000 acre-feet (acre-ft) of recharge diversions occur above American Falls Reservoir and 212,000 acre-ft is diverted at Milner Dam. The 2021 IRP included approximately 55,000 acre-feet of additional annual recharge not included in the 2019 IRP. This increase in projected recharge activity is based upon recharge activity observed from spring 2016 through spring 2020. The additional annual recharge volume can be attributed to the development of private aquifer recharge and state sponsored storage water recharge demonstrating a higher level of recharge capacity than anticipated in the 2019 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 (IDWR) and local ground water districts. The current model assumes approximately 57,000 acres of converted land on the ESPA. Water savings for conversion projects are calculated at a rate of 2.0 acre-ft/converted acre. Diversions for conversion projects are modeled at approximately 114,000 acre-ft and are held essentially constant through all years of the IRP. The model accounted for approximately 140,000 acre-ft decrease in ground water pumping from the ESPA.

The decrease was spread evenly over ground water irrigated lands subject to the agreement between the SWC and the IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft per year (acre-ft/year), but the agreement allows for a portion to be offset by aquifer recharge activities. Based on recent management activity, approximately 100,000 acre-ft/year reduction is accomplished through other forms of mitigation, such as private aquifer recharge.

The 2021 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using several statistical analyses. Trend data indicate reach gains from Blackfoot to Neely and from Lower Salmon Falls Dam to King Hill demonstrated a statistically significant decline from 1990 to 2019. The long-term declines are still present, but they have improved since the 2019 IRP. Reach gains to the Snake River increased since 2017. The increases in reach gains may be due to recent high runoff events, good supply of irrigation water, and aquifer recharge activities. 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 2021 through 2026, weather modification reflects the current 2020 level of program development in Eastern Idaho and the Wood River, Boise, and Payette basins. Beyond IRP year 2026, weather modification levels in Eastern Idaho and the Wood River and Boise basins were increased due to an anticipation of expanding the cloud seeding program. 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 since 2014. Idaho Power used data from IDWR and other sources 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.

Hydro Model Results

The modeling methods implemented by Idaho Power allows for the inclusion of all future management activities, and the resulting reach gains from those management activities into Idaho Power’s 2021 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the 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 2021 through 2026. Flows peak in 2026 with the 50% exceedance water year annual inflow to Brownlee Reservoir at just over 12.86 million acre-ft/year. In 2040, those flows declined to approximately 12.59 million acre-ft/year.

The Brownlee inflow volumes for the 2021 IRP are higher than those reported in the 2019 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 2038 the increase in Brownlee inflow volume attributable to changes in reach declines between the 2021 and 2019 IRPs is approximately 380,000 acre-feet. Weather modification volume increased by approximately 10,000 acre-ft/year in the 2021 IRP as compared to the 2019 IRP. The other notable change is the observed recharge conducted in 2018 through 2020 exceeded recharge volume assumptions made during the 2019 IRP. Over 1,000,000 acre-ft water were recharged to the ESPA during 2018 through 2020. While outside the modeling period of 2021 to 2040, 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.

2021 Hydro 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
2021	194,877	212,336	407,213	1,005,582	114,236	140,047	17,807	19,724
2022	194,877	212,336	407,213	1,005,582	114,236	140,047	29,341	32,500
2023	194,877	212,336	407,213	1,005,582	114,236	140,047	40,876	45,276
2024	194,877	212,336	407,213	1,005,582	114,236	140,047	52,542	58,197
2025	194,877	212,336	407,213	1,005,582	114,236	140,047	63,944	70,827
2026	194,877	212,336	407,213	1,279,757	114,236	140,047	75,478	83,603
2027	194,877	212,336	407,213	1,279,757	114,236	140,047	87,013	96,379
2028	194,877	212,336	407,213	1,279,757	114,236	140,047	98,805	109,441
2029	194,877	212,336	407,213	1,279,757	114,236	140,047	110,081	121,931
2030	194,877	212,336	407,213	1,279,757	114,236	140,047	121,615	134,707
2031	194,877	212,336	407,213	1,279,757	114,236	140,047	133,150	147,483
2032	194,877	212,336	407,213	1,279,757	114,236	140,047	145,069	160,684
2033	194,877	212,336	407,213	1,279,757	114,236	140,047	156,218	173,034
2034	194,877	212,336	407,213	1,279,757	114,236	140,047	167,753	185,810
2035	194,877	212,336	407,213	1,279,757	114,236	140,047	179,287	198,586
2036	194,877	212,336	407,213	1,279,757	114,236	140,047	191,332	211,928
2037	194,877	212,336	407,213	1,279,757	114,236	140,047	202,355	224,138
2038	194,877	212,336	407,213	1,279,757	114,236	140,047	213,890	236,914
2039	194,877	212,336	407,213	1,279,757	114,236	140,047	225,424	249,690
2040	194,877	212,336	407,213	1,279,757	114,236	140,047	237,596	263,171

Hydro Modeling Results (aMW)

Year	Month	50th Percentile (planning case) HCC*	ROR**	Total	Climate Change Modeling HCC	ROR	Total
2021	Jan	765	312	1,077	1198	558	1,757
	Feb	960	337	1,297	1189	510	1,699
	Mar	865	389	1,253	1160	562	1,722
	Apr	1073	411	1,484	1198	595	1,794
	May	941	365	1,306	1208	596	1,804
	June	902	403	1,305	1267	524	1,792
	July	621	389	1,011	899	426	1,325
	Aug	512	298	810	627	414	1,041
	Sept	637	250	887	750	257	1,007
	Oct	423	226	650	473	240	713
	Nov	340	219	559	331	237	567
	Dec	514	219	733	602	358	959
Annual aMW		**713**	**318**	**1,031**	**909**	**440**	**1,348**
2022	Jan	763	311	1,074	1218	544	1,762
	Feb	958	337	1,295	1187	502	1,689
	Mar	863	388	1,251	1139	580	1,719
	Apr	1071	410	1,481	1126	583	1,708
	May	940	365	1,305	1094	582	1,676
	June	901	403	1,303	1306	582	1,888
	July	620	389	1,009	817	395	1,212
	Aug	511	297	808	652	436	1,088
	Sept	635	250	885	687	260	947
	Oct	423	226	649	430	239	670
	Nov	340	219	559	330	219	549
	Dec	514	218	732	591	362	953
Annual aMW		**712**	**318**	**1,029**	**881**	**440**	**1,322**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2023	Jan	762	311	1,072	1154	545	1,699
	Feb	957	336	1,293	1126	497	1,623
	Mar	863	387	1,249	1113	444	1,557
	Apr	1072	409	1,481	1185	462	1,647
	May	940	365	1,305	923	517	1,439
	June	900	402	1,302	893	422	1,315
	July	620	389	1,009	615	405	1,019
	Aug	511	297	808	462	281	743
	Sept	634	250	884	630	241	871
	Oct	422	226	648	397	234	631
	Nov	340	219	559	335	221	556
	Dec	513	218	732	451	194	645
Annual aMW		**711**	**317**	**1,028**	**774**	**372**	**1,145**
2024	Jan	761	310	1,071	561	282	843
	Feb	956	336	1,292	620	284	903
	Mar	862	386	1,248	529	281	810
	Apr	1071	408	1,480	537	218	755
	May	940	364	1,304	546	234	780
	June	899	402	1,301	501	338	839
	July	619	389	1,008	462	264	726
	Aug	510	297	807	399	201	599
	Sept	633	249	882	421	201	622
	Oct	422	226	647	353	197	550
	Nov	340	219	559	340	194	534
	Dec	513	218	731	434	187	621
Annual aMW		**710**	**317**	**1,027**	**475**	**240**	**715**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2025	Jan	760	309	1,069	564	197	762
	Feb	955	334	1,289	594	186	781
	Mar	860	385	1,246	619	205	824
	Apr	1071	408	1,479	879	202	1,081
	May	939	364	1,303	667	291	957
	June	899	402	1,300	750	261	1,012
	July	619	388	1,007	490	251	741
	Aug	510	297	806	421	194	614
	Sept	631	249	881	389	198	587
	Oct	421	225	647	361	197	558
	Nov	340	219	559	346	189	535
	Dec	513	218	730	430	185	616
Annual aMW		**710**	**317**	**1,026**	**543**	**213**	**756**
2026	Jan	783	324	1,107	619	220	838
	Feb	975	351	1,327	703	222	925
	Mar	884	399	1,282	507	189	696
	Apr	1089	441	1,530	675	191	866
	May	940	379	1,319	950	238	1,188
	June	914	412	1,326	816	252	1,068
	July	621	396	1,017	533	286	820
	Aug	511	302	813	425	217	642
	Sept	633	250	882	373	206	579
	Oct	422	226	647	362	193	554
	Nov	340	219	559	350	185	535
	Dec	513	218	732	424	188	612
Annual aMW		**719**	**326**	**1,045**	**561**	**216**	**777**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2027	Jan	780	323	1,103	533	185	719
	Feb	974	350	1,325	688	205	893
	Mar	882	397	1,280	669	194	863
	Apr	1089	440	1,529	670	191	861
	May	939	378	1,318	719	268	987
	June	913	412	1,324	662	244	906
	July	620	396	1,016	502	260	763
	Aug	510	302	812	437	211	648
	Sept	631	250	881	463	202	665
	Oct	421	225	647	377	189	566
	Nov	340	219	559	332	183	516
	Dec	513	218	731	453	185	637
Annual aMW		**718**	**326**	**1,044**	**542**	**210**	**752**
2028	Jan	778	322	1,100	538	246	784
	Feb	973	349	1,322	550	226	776
	Mar	881	396	1,277	416	213	629
	Apr	1089	440	1,529	562	222	784
	May	939	376	1,315	903	265	1,167
	June	912	411	1,323	655	249	905
	July	620	395	1,015	582	371	953
	Aug	510	301	810	451	268	719
	Sept	630	249	879	462	219	682
	Oct	421	225	646	370	201	571
	Nov	340	219	559	348	189	537
	Dec	513	218	730	645	178	823
Annual aMW		**717**	**325**	**1,042**	**540**	**237**	**777**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2029	Jan	775	321	1,095	1119	282	1,400
	Feb	972	348	1,320	1142	217	1,359
	Mar	880	395	1,275	1148	285	1,433
	Apr	1089	439	1,528	1193	537	1,730
	May	939	375	1,314	1218	509	1,728
	June	912	410	1,322	1101	472	1,573
	July	619	395	1,014	631	416	1,047
	Aug	509	300	809	492	285	777
	Sept	628	249	878	566	237	803
	Oct	420	225	645	391	209	601
	Nov	340	219	559	338	190	528
	Dec	512	218	730	495	197	692
Annual aMW		**716**	**325**	**1,041**	**820**	**320**	**1,139**
2030	Jan	773	319	1,092	605	321	926
	Feb	970	347	1,317	724	347	1,071
	Mar	879	394	1,273	627	379	1,007
	Apr	1089	438	1,527	638	309	947
	May	938	376	1,314	675	235	910
	June	911	410	1,321	542	347	889
	July	618	395	1,013	475	270	745
	Aug	508	300	809	405	222	627
	Sept	627	249	876	511	215	725
	Oct	419	225	644	368	198	566
	Nov	340	219	559	336	187	522
	Dec	511	217	729	426	187	612
Annual aMW		**715**	**324**	**1,039**	**528**	**268**	**796**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2031	Jan	771	318	1,089	541	217	758
	Feb	969	345	1,314	641	225	866
	Mar	877	393	1,270	665	228	893
	Apr	1088	437	1,525	799	332	1,131
	May	938	375	1,313	934	243	1,178
	June	909	410	1,319	945	258	1,203
	July	618	394	1,012	596	324	920
	Aug	508	300	808	484	325	809
	Sept	625	249	874	482	223	705
	Oct	419	225	644	392	203	595
	Nov	340	218	558	342	187	528
	Dec	511	217	728	421	184	604
Annual aMW		**714**	**323**	**1,038**	**603**	**246**	**849**
2032	Jan	768	317	1,085	602	300	902
	Feb	967	344	1,310	690	285	975
	Mar	877	392	1,269	767	418	1,185
	Apr	1087	436	1,523	1118	551	1,668
	May	940	378	1,319	1032	442	1,474
	June	908	410	1,318	1118	528	1,646
	July	617	394	1,011	627	389	1,016
	Aug	507	300	807	514	351	865
	Sept	624	248	872	482	234	716
	Oct	418	224	643	389	215	604
	Nov	340	218	558	346	190	536
	Dec	510	217	728	438	188	626
Annual aMW		**714**	**323**	**1,037**	**677**	**341**	**1,018**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2033	Jan	765	315	1,080	651	332	983
	Feb	965	342	1,307	732	330	1,061
	Mar	876	391	1,266	646	321	967
	Apr	1086	435	1,521	757	273	1,030
	May	940	378	1,318	840	315	1,155
	June	907	409	1,316	1129	307	1,435
	July	616	394	1,010	515	293	807
	Aug	506	299	806	442	240	682
	Sept	622	248	870	503	228	730
	Oct	418	224	642	394	215	609
	Nov	340	218	558	340	196	535
	Dec	510	217	727	522	182	704
Annual aMW		**713**	**322**	**1,035**	**622**	**269**	**892**
2034	Jan	762	313	1,075	873	296	1,170
	Feb	963	341	1,304	1083	301	1,384
	Mar	873	389	1,263	1120	532	1,653
	Apr	1086	435	1,521	1113	513	1,626
	May	939	377	1,317	1067	499	1,566
	June	906	408	1,315	1293	583	1,875
	July	615	393	1,009	1092	546	1,638
	Aug	506	299	805	691	437	1,127
	Sept	621	248	868	649	252	901
	Oct	417	224	641	422	222	644
	Nov	340	218	558	341	194	535
	Dec	509	217	726	634	454	1,088
Annual aMW		**712**	**322**	**1,033**	**865**	**402**	**1,267**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2035	Jan	760	312	1,071	1103	536	1,640
	Feb	961	339	1,301	1152	476	1,628
	Mar	872	388	1,260	1097	486	1,583
	Apr	1085	434	1,519	1108	495	1,603
	May	939	376	1,315	725	391	1,116
	June	905	408	1,313	538	337	875
	July	615	393	1,008	617	405	1,022
	Aug	505	299	804	457	277	734
	Sept	619	247	867	589	229	818
	Oct	417	224	640	381	210	591
	Nov	340	218	558	329	192	521
	Dec	509	216	725	438	199	637
Annual aMW		**711**	**321**	**1,032**	**711**	**353**	**1,064**
2036	Jan	757	310	1,067	505	223	728
	Feb	960	338	1,298	641	260	901
	Mar	870	386	1,257	460	234	693
	Apr	1084	433	1,517	487	190	677
	May	939	376	1,314	532	233	766
	June	904	407	1,311	532	337	868
	July	614	393	1,006	427	271	698
	Aug	505	299	803	370	203	573
	Sept	618	247	865	436	203	639
	Oct	416	223	640	382	193	575
	Nov	340	218	558	344	185	529
	Dec	508	216	724	411	178	589
Annual aMW		**710**	**320**	**1,030**	**461**	**226**	**686**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2037	Jan	755	308	1,063	452	174	626
	Feb	958	336	1,294	616	196	812
	Mar	868	384	1,252	756	216	972
	Apr	1082	432	1,514	781	388	1,169
	May	938	376	1,314	695	255	949
	June	903	407	1,310	619	237	856
	July	613	392	1,005	506	372	878
	Aug	504	298	802	442	272	714
	Sept	616	247	863	441	218	659
	Oct	416	223	639	376	209	585
	Nov	340	217	558	339	184	524
	Dec	508	216	724	504	191	695
Annual aMW		**708**	**320**	**1,028**	**544**	**243**	**787**
2038	Jan	752	306	1,059	675	344	1,019
	Feb	956	334	1,290	945	372	1,318
	Mar	866	382	1,248	605	339	944
	Apr	1083	431	1,514	545	315	860
	May	938	375	1,313	473	262	736
	June	902	406	1,308	462	310	772
	July	612	391	1,003	487	367	854
	Aug	504	298	802	361	245	606
	Sept	614	246	861	387	224	611
	Oct	415	223	638	362	199	561
	Nov	340	217	557	342	186	528
	Dec	507	216	723	477	171	648
Annual aMW		**707**	**319**	**1,026**	**510**	**278**	**788**

*HCC=Hells Canyon Complex, **ROR=Run of River

Year	Month	50th Percentile (planning case) HCC	ROR	Total	Climate Change Modeling HCC	ROR	Total
2039	Jan	750	305	1,054	579	240	819
	Feb	954	333	1,287	741	255	996
	Mar	864	381	1,245	777	218	995
	Apr	1082	430	1,512	922	210	1,132
	May	937	373	1,310	830	243	1,072
	June	900	406	1,306	568	247	815
	July	612	391	1,002	499	348	847
	Aug	503	298	801	395	233	629
	Sept	613	246	859	440	211	650
	Oct	415	223	637	373	187	560
	Nov	340	217	557	343	165	509
	Dec	507	215	722	448	173	621
Annual aMW		**707**	**318**	**1,024**	**576**	**228**	**804**
2040	Jan	748	302	1,050	819	318	1,137
	Feb	952	331	1,283	1179	463	1,642
	Mar	863	379	1,242	1129	580	1,709
	Apr	1081	429	1,510	1144	584	1,728
	May	937	372	1,309	1181	583	1,765
	June	899	405	1,304	1243	506	1,749
	July	611	392	1,003	642	359	1,001
	Aug	503	297	800	548	363	911
	Sept	611	246	857	636	236	872
	Oct	414	222	637	410	212	623
	Nov	340	217	557	329	207	537
	Dec	506	215	722	462	184	646
Annual aMW		**706**	**317**	**1,023**	**810**	**383**	**1,193**

*HCC=Hells Canyon Complex, **ROR=Run of River

LONG-TERM CAPACITY EXPANSION RESULTS (MW)

Preferred Portfolio—Base with B2H

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

Base with B2H—High Gas High Carbon Test (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	105	0	20	-308	27	0
2026	0	0	515	0	500	0	0	28	0
2027	0	0	250	0	0	0	0	27	0
2028	0	400	320	0	GW1	0	-175	27	0
2029	0	100	100	200	0	0	0	26	0
2030	0	100	0	55	GW2	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	0	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	357	1,300	1,805	1,570	500	400	-841	428	12
Total	**5,531**								

Base with B2H—PAC Bridger Alignment (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	0	0	20	0	25	0
2025	0	0	300	105	0	0	-134	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	0	0	0	0	27	0
2028	0	0	120	0	0	0	0	27	0
2029	0	0	0	5	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	5	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	105	0	0	0	22	0
2034	-357	0	100	305	0	0	-349	21	0
2035	0	0	200	505	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	100	105	0	0	0	14	0
2038	0	0	0	155	0	0	0	12	0
2039	0	100	0	55	GW1	0	0	11	0
2040	0	100	0	55	0	0	0	10	0
Subtotal	0	900	1,405	1,680	500	340	-841	428	0
Total	**4,412**								

Base without B2H (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	900	0	0	0	0	0	25	0
2025	0	0	400	205	0	0	-308	27	0
2026	0	0	515	305	GW1	0	0	28	0
2027	0	0	250	105	0	0	-175	27	0
2028	0	200	320	205	GW2	20	0	27	0
2029	0	100	0	50	0	0	0	26	0
2030	0	100	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	105	0	0	0	22	0
2034	-357	0	100	155	0	0	0	21	0
2035	0	0	100	300	0	0	0	20	0
2036	0	0	0	55	0	20	0	16	0
2037	0	0	0	100	0	0	0	14	6
2038	0	0	0	150	0	20	0	12	6
2039	0	0	0	50	0	40	0	11	3
2040	0	0	0	50	0	20	0	10	9
Subtotal	0	1,300	1,805	2,115	0	440	-841	428	23
Total	**5,271**								

Base without B2H, without Gateway West (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	130	0	20	-357	24	0
2024	357	400	0	20	0	20	0	25	0
2025	0	0	200	120	0	0	-134	27	0
2026	0	0	215	270	0	0	0	28	0
2027	0	0	250	70	0	20	0	27	0
2028	0	0	120	120	0	0	-175	27	0
2029	0	200	0	220	0	0	0	26	0
2030	0	200	0	20	0	0	0	24	0
2031	0	0	0	70	0	0	0	24	0
2032	0	0	0	60	0	0	-174	23	0
2033	0	0	0	265	0	0	0	22	0
2034	-357	0	0	265	0	0	0	21	0
2035	0	0	0	205	0	20	0	20	8
2036	0	0	0	60	0	0	0	16	11
2037	0	0	0	120	0	0	0	14	6
2038	0	0	0	170	0	0	0	12	6
2039	0	0	0	70	0	20	0	11	6
2040	0	0	0	170	0	20	0	10	3
Subtotal	0	800	905	2,425	0	420	-841	428	40
Total	**4,177**								

Base without B2H—PAC Bridger Alignment (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	800	0	0	0	0	0	25	0
2025	0	0	400	205	0	0	-134	27	0
2026	0	0	215	155	0	0	0	28	0
2027	0	200	250	55	GW1	0	0	27	0
2028	0	0	120	105	0	0	0	27	0
2029	0	100	0	50	0	0	0	26	0
2030	0	100	100	100	0	0	0	24	0
2031	0	0	0	0	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	100	100	GW2	0	0	22	0
2034	-357	0	100	305	0	0	-349	21	0
2035	0	0	300	505	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	100	100	0	0	0	14	0
2038	0	0	100	150	0	0	0	12	6
2039	0	0	0	55	0	0	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	1,200	1,905	2,165	0	340	-841	428	18
Total	**5,215**								

Rapid Electrification (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	14
2024	357	800	0	5	0	0	0	25	0
2025	0	0	300	105	0	0	-308	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	105	0	0	0	27	0
2029	0	100	0	55	0	0	-175	26	0
2030	0	300	0	205	GW1	0	0	24	0
2031	0	0	100	105	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	55	0	0	0	22	0
2034	-357	0	100	105	0	0	0	21	0
2035	0	0	100	405	0	20	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	6
2038	0	0	100	205	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	0
2040	0	200	100	5	GW2	40	0	10	0
Subtotal	0	1,400	1,505	1,745	500	420	-841	428	20
Total	**5,178**								

Climate Change (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	215	0	20	-357	24	30
2024	357	900	400	5	0	20	0	25	0
2025	0	0	400	105	0	0	-308	27	0
2026	0	0	215	5	500	0	0	28	0
2027	0	0	250	5	GW1	0	0	27	0
2028	0	300	120	5	0	0	-175	27	0
2029	0	0	200	255	GW2	0	0	26	0
2030	0	100	100	5	0	0	0	24	0
2031	0	0	100	105	0	0	0	24	0
2032	0	0	0	5	0	0	0	23	0
2033	0	0	100	150	0	0	0	22	0
2034	-357	0	100	105	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	100	105	0	0	0	14	0
2038	0	0	100	255	0	0	0	12	6
2039	0	0	0	55	0	0	0	11	6
2040	0	0	100	55	0	0	0	10	9
Subtotal	0	1,300	2,505	1,795	500	340	-841	428	50
Total	**6,078**								

100% Clean by 2035 (MW)

Year	Gas	Wind	Solar	Storage	Nuclear	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	0	20	-357	24	0
2024	357	900	0	0	0	0	0	0	25	0
2025	0	0	400	205	0	0	0	-308	27	0
2026	0	0	515	305	0	500	0	0	28	0
2027	0	0	250	105	0	GW1	0	-175	27	0
2028	0	200	320	205	0	0	20	0	27	0
2029	0	100	0	50	0	0	0	0	26	0
2030	-45	100	0	55	0	GW2	0	0	24	0
2031	-45	0	0	55	77	0	0	0	24	0
2032	-164	0	0	55	0	0	0	0	23	0
2033	-171	0	0	105	154	0	0	0	22	0
2034	-693	0	100	155	154	0	0	0	21	0
2035	0	0	100	300	308	0	0	0	20	0
2036	0	0	0	55	0	0	20	0	16	0
2037	0	0	0	100	0	0	0	0	14	6
2038	0	0	0	150	0	0	20	0	12	6
2039	0	0	0	50	0	0	40	0	11	3
2040	0	0	0	50	0	0	20	0	10	9
Subtotal	-762	1,300	1,805	2,115	693	500	440	-841	428	23
Total	**5,702**									

100% Clean by 2045 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	-134	25	0
2025	0	0	900	200	0	0	-174	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	GW1	0	-175	27	0
2028	0	0	220	105	0	0	0	27	0
2029	0	0	0	55	0	0	0	26	0
2030	0	0	100	105	0	0	0	24	0
2031	0	0	0	5	0	0	0	24	0
2032	0	0	0	55	0	20	0	23	0
2033	0	0	0	55	0	20	0	22	0
2034	-357	0	0	155	0	20	0	21	0
2035	0	0	100	305	0	20	0	20	0
2036	0	0	0	55	0	20	0	16	0
2037	0	0	0	105	0	20	0	14	0
2038	0	0	0	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	9
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	700	1,905	1,590	500	500	-841	428	18
Total	**4,800**								

SWIP North (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	800	0	0	0	0	0	25	0
2025	0	0	200	0	100[1]	0	-308	27	0
2026	0	0	215	5	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	55	0	0	-175	27	0
2029	0	300	0	205	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	100	100	GW1	0	0	24	0
2032	0	100	0	5	0	0	0	23	0
2033	0	0	100	105	0	0	0	22	0
2034	-357	0	0	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	8
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	150	0	20	0	12	6
2039	0	0	0	50	0	20	0	11	0
2040	0	100	0	55	0	0	0	10	0
Subtotal	0	1,300	1,305	1,520	600	360	-841	428	13
Total	**4,686**								

1. SWIP North Capacity

CSPP Wind Renewal Low (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	100	0	20	-308	27	0
2026	0	0	215	5	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	55	0	0	-175	27	0
2029	0	0	100	250	0	0	0	26	0
2030	0	0	0	50	0	0	0	24	0
2031	0	0	100	105	0	0	0	24	0
2032	0	100	0	5	0	0	0	23	0
2033	0	0	0	105	0	0	0	22	0
2034	-357	0	0	155	0	0	0	21	0
2035	0	0	100	305	0	20	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	GW1	0	0	12	9
2039	0	100	0	55	0	0	0	11	0
2040	0	100	0	50	0	0	0	10	6
Subtotal	0	1,000	1,405	1,680	500	360	-841	428	15
Total	**4,547**								

CSPP Wind Renewal High (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	0	0	20	0	25	0
2025	0	0	300	105	0	0	-308	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	0	0	0	0	27	0
2028	0	0	120	100	0	0	-175	27	0
2029	0	0	0	200	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	100	0	50	0	0	0	24	0
2032	0	0	0	50	0	0	0	23	0
2033	0	0	0	50	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	100	100	300	0	0	0	20	0
2036	0	0	0	55	0	20	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	150	GW1	0	0	12	0
2039	0	0	0	50	0	0	0	11	0
2040	0	200	300	5	0	20	0	10	0
Subtotal	0	1,100	1,605	1,540	500	380	-841	428	0
Total	**4,712**								

Validation Test: Natural Gas in 2028 Rather Than Solar and Storage (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	105	0	20	-308	27	0
2026	0	0	215	5	500	0	0	28	0
2027	0	0	250	5	0	0	-175	27	0
2028	170	0	120	55	0	0	0	27	0
2029	0	0	0	55	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	105	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	55	0	0	0	22	0
2034	-357	0	0	55	0	0	0	21	0
2035	0	0	100	405	0	20	0	20	0
2036	0	0	0	100	0	0	0	16	0
2037	0	0	0	50	0	0	0	14	3
2038	0	0	100	205	0	0	0	12	6
2039	0	0	0	55	0	0	0	11	0
2040	0	300	0	5	GW1	20	0	10	6
Subtotal	170	1,000	1,205	1,490	500	380	-841	428	15
Total	**4,347**								

Validation Test: Bridger Exit Units 1 and 2 at the End of 2023 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	0	400	400	400	0	0	0	25	0
2025	0	0	300	100	0	0	-308	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	55	0	0	-175	27	0
2029	0	0	100	250	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	100	100	0	0	0	23	0
2033	0	100	0	0	0	20	0	22	0
2034	0	0	0	55	0	0	0	21	10
2035	0	100	0	55	GW1	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	100	0	155	0	0	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	100	0	55	0	0	0	10	0
Subtotal	0	800	1,605	1,670	500	360	-841	428	13
Total	**4,535**								

Validation Test: Bridger Exit Unit 2 at the End of 2026 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-177	24	0
2024	177	800	0	0	0	0	0	25	0
2025	0	0	300	105	0	0	-308	27	0
2026	0	0	215	0	500	0	-180	28	0
2027	0	0	250	150	0	0	0	27	0
2028	0	0	120	105	0	0	-175	27	0
2029	0	0	200	250	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	100	0	55	0	0	0	22	0
2034	-177	100	0	55	GW1	0	0	21	0
2035	0	0	100	255	0	0	0	20	0
2036	0	0	0	105	0	0	0	16	8
2037	0	0	0	0	0	20	0	14	6
2038	0	100	100	155	0	20	0	12	6
2039	0	0	0	55	0	20	0	11	6
2040	0	0	0	55	0	40	0	10	6
Subtotal	0	1,100	1,405	1,625	500	420	-841	428	31
Total	**4,669**								

Validation Test: Bridger Exit Units 3 and 4 in 2028 and 2030 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	0	25	0
2025	0	0	300	100	0	20	-134	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	27	0
2028	0	0	120	5	0	0	-174	27	0
2029	0	0	0	105	0	20	0	26	0
2030	0	0	0	55	0	0	-175	24	0
2031	0	0	0	255	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	200	0	0	0	21	0
2035	0	100	100	250	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	100	100	0	0	0	14	0
2038	0	0	100	155	GW1	20	0	12	6
2039	0	0	0	50	0	20	0	11	0
2040	0	0	0	50	0	20	0	10	9
Subtotal	0	800	1,405	1,660	500	420	-841	428	15
Total	**4,387**								

Validation Test: Valmy Unit 2 Exit in 2023 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-491	24	0
2024	357	600	100	150	0	0	0	25	0
2025	0	0	300	105	0	0	-174	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	0	0	0	-175	27	0
2028	0	0	220	105	0	0	0	27	0
2029	0	0	0	55	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	100	0	100	0	0	0	24	0
2032	0	100	0	5	0	0	0	23	0
2033	0	0	0	105	0	0	0	22	0
2034	-357	0	0	205	0	0	0	21	0
2035	0	0	100	255	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	GW1	0	0	12	0
2039	0	100	0	105	0	0	0	11	0
2040	0	0	0	55	0	20	0	10	0
Subtotal	0	900	1,405	1,730	500	340	-841	428	0
Total	**4,462**								

Validation Test: Valmy Unit 2 Exit in 2024 (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	5	0	0	-134	25	0
2025	0	0	400	250	0	0	-174	27	0
2026	0	0	215	0	500	0	0	28	0
2027	0	0	250	5	0	0	-175	27	0
2028	0	0	120	105	0	0	0	27	0
2029	0	0	0	55	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	100	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	105	0	0	0	22	0
2034	-357	0	100	155	0	0	0	21	0
2035	0	0	100	300	0	0	0	20	0
2036	0	0	0	50	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	100	0	155	GW1	0	0	12	0
2039	0	0	0	55	0	20	0	11	0
2040	0	0	100	105	0	0	0	10	0
Subtotal	0	900	1,405	1,730	500	340	-841	428	0
Total	**4,462**								

Validation Test: Biomass (MW)

Year	Gas	Wind	Solar	Storage	Biomass	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	0	20	-357	24	0
2024	357	700	0	5	0	0	0	0	25	0
2025	0	0	300	105	0	0	20	-308	27	0
2026	0	0	215	0	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	0	27	0
2028	0	0	120	5	50	0	0	-175	27	0
2029	0	0	100	255	0	0	0	0	26	0
2030	0	0	0	55	0	0	0	0	24	0
2031	0	0	0	55	0	0	0	0	24	0
2032	0	0	0	55	0	0	0	0	23	0
2033	0	0	0	100	0	0	0	0	22	0
2034	-357	0	100	150	0	0	0	0	21	0
2035	0	0	100	305	0	0	0	0	20	0
2036	0	0	0	55	0	0	0	0	16	0
2037	0	0	0	105	0	0	0	0	14	0
2038	0	0	100	155	0	0	20	0	12	0
2039	0	0	0	55	0	0	20	0	11	3
2040	0	0	0	55	0	0	20	0	10	9
Subtotal	0	700	1,405	1,635	50	500	400	-841	428	12
Total	**4,289**									

Validation Test: Geothermal (MW)

Year	Gas	Wind	Solar	Storage	Geothermal	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	0	20	-357	24	0
2024	357	700	0	5	0	0	0	0	25	0
2025	0	0	300	105	0	0	20	-308	27	0
2026	0	0	215	0	0	500	0	0	28	0
2027	0	0	250	5	0	0	0	0	27	0
2028	0	0	120	5	50	0	0	-175	27	0
2029	0	0	100	255	0	0	0	0	26	0
2030	0	0	0	55	0	0	0	0	24	0
2031	0	0	0	55	0	0	0	0	24	0
2032	0	0	0	55	0	0	0	0	23	0
2033	0	0	0	100	0	0	0	0	22	0
2034	-357	0	100	150	0	0	0	0	21	0
2035	0	0	100	305	0	0	0	0	20	0
2036	0	0	0	55	0	0	0	0	16	0
2037	0	0	0	105	0	0	0	0	14	0
2038	0	0	100	155	0	0	20	0	12	0
2039	0	0	0	55	0	0	20	0	11	3
2040	0	0	0	55	0	0	20	0	10	9
Subtotal	0	700	1,405	1,635	50	500	400	-841	428	12
Total	**4,289**									

Validation Test: Demand Response (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	115	0	20	-357	24	0
2024	357	700	0	0	0	20	0	25	0
2025	0	0	300	100	0	20	-308	27	0
2026	0	0	215	0	500	20	0	28	0
2027	0	0	250	0	0	20	0	27	0
2028	0	0	120	50	0	0	-175	27	0
2029	0	0	100	255	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	700	1,405	1,665	500	460	-841	428	12
Total	**4,329**								

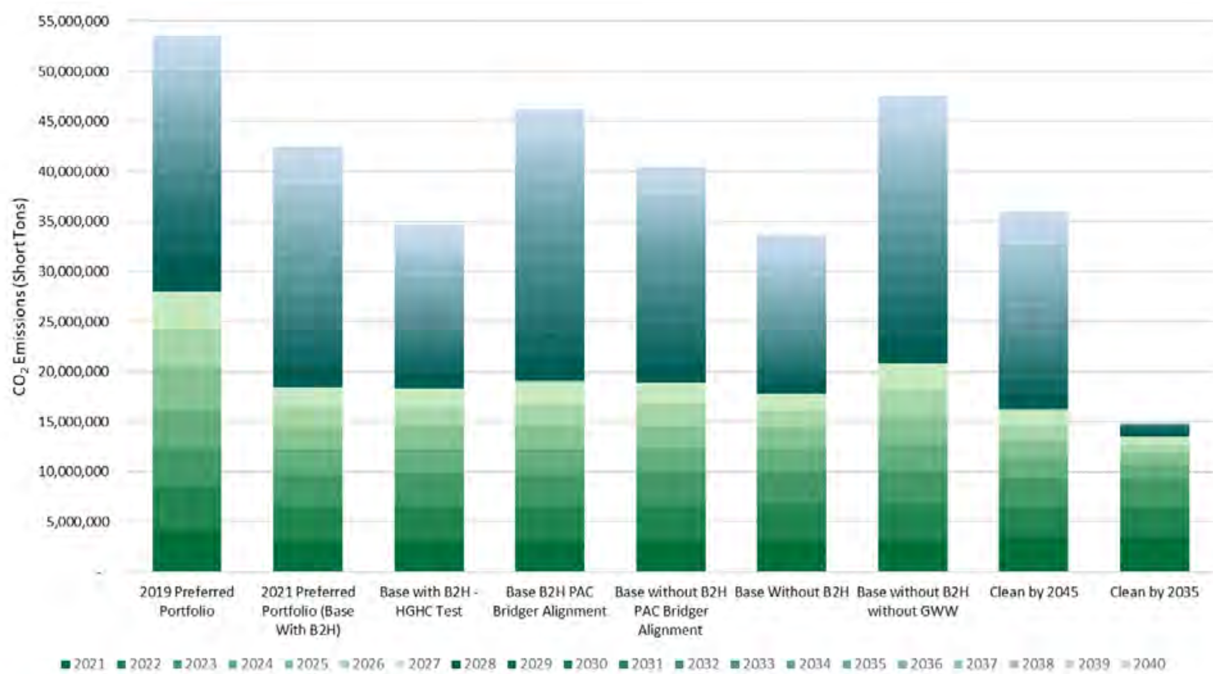
Validation Test: Energy Efficiency (MW)

Year	Gas	Wind	Solar	Storage	Transmission	Demand Response	Coal Exit	Energy Efficiency Forecast	Energy Efficiency Bundles
2021	0	0	0	0	0	0	0	23	0
2022	0	0	0	0	0	300	0	24	0
2023	0	0	120	110	0	20	-357	24	14
2024	357	700	0	0	0	0	0	25	18
2025	0	0	300	100	0	20	-308	27	22
2026	0	0	215	0	500	0	0	28	25
2027	0	0	250	0	0	0	0	27	26
2028	0	0	120	40	0	0	-175	27	0
2029	0	0	100	255	0	0	0	26	0
2030	0	0	0	55	0	0	0	24	0
2031	0	0	0	55	0	0	0	24	0
2032	0	0	0	55	0	0	0	23	0
2033	0	0	0	100	0	0	0	22	0
2034	-357	0	100	150	0	0	0	21	0
2035	0	0	100	305	0	0	0	20	0
2036	0	0	0	55	0	0	0	16	0
2037	0	0	0	105	0	0	0	14	0
2038	0	0	100	155	0	20	0	12	0
2039	0	0	0	55	0	20	0	11	3
2040	0	0	0	55	0	20	0	10	9
Subtotal	0	700	1,405	1,650	500	400	-841	428	117
Total	**4,359**								

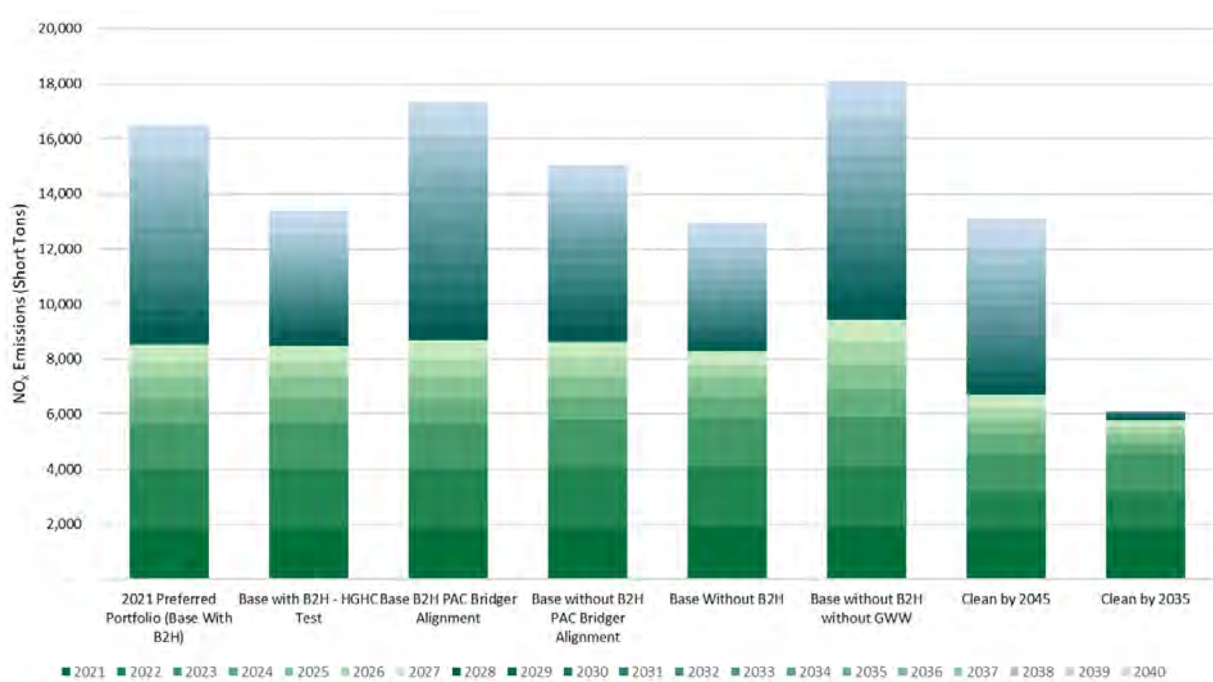
PORTFOLIO EMISSIONS FORECAST

Total emissions forecasts (CO_2, NO_x, and SO_2) for Idaho Power's resources are outputs of the AURORA model and are presented below.

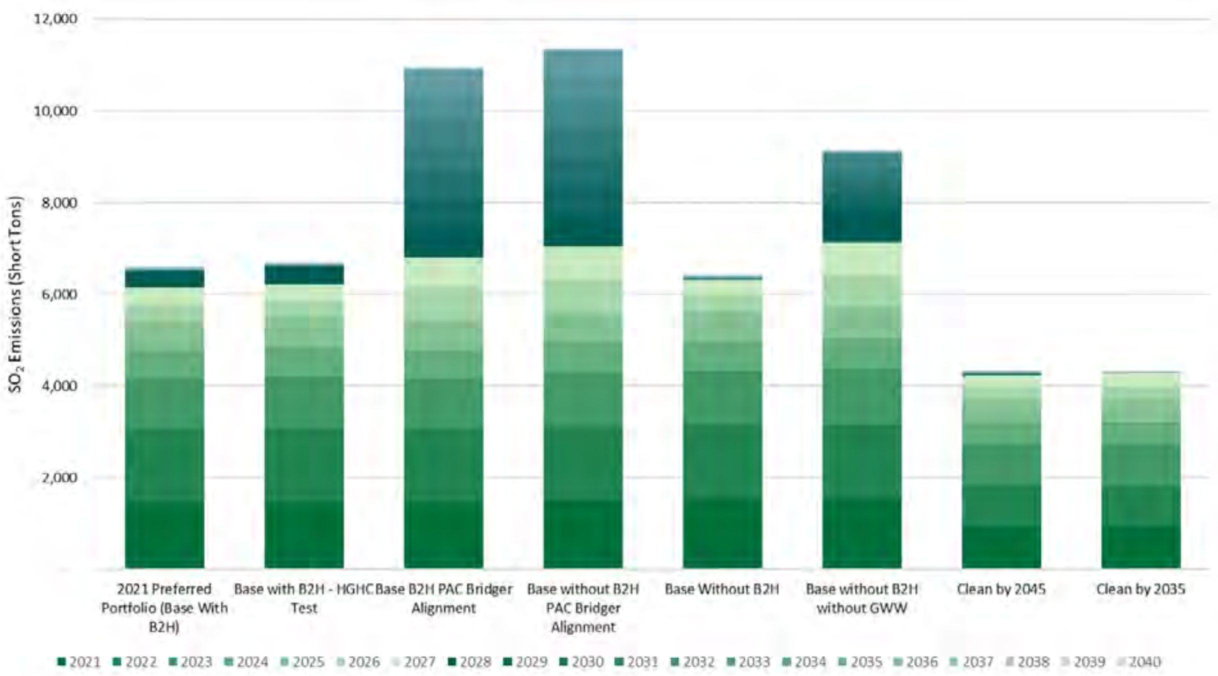
CO_2 Tons



NOx Tons



SO_2 Tons



12,000
10,000
8,000
6,000
4,000
2,000
SO_2 Emissions (Short Tons)
2021 Preferred Portfolio (Base With B2H)
Base with B2H - HGHC Test
Base B2H PAC Bridger Alignment
Base without B2H PAC Bridger Alignment
Base Without B2H
Base without B2H without GWW
Clean by 2045
Clean by 2035
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040

Preferred Portfolio (Base with B2H) Emissions

Year	CO_2 (short tons)	NOx (short tons)	SO_2 (short tons)
2021	3,146,734	1,825	1,459
2022	3,464,248	2,175	1,588
2023	3,133,471	1,656	1,119
2024	2,428,049	857	639
2025	2,304,014	801	649
2026	2,014,136	604	348
2027	2,025,337	611	339
2028	2,111,398	652	348
2029	1,748,562	558	9
2030	1,725,706	555	9
2031	1,787,393	590	9
2032	1,831,248	608	10
2033	1,905,600	633	10
2034	1,889,374	631	10
2035	1,783,130	606	9
2036	1,787,069	611	9
2037	1,809,568	617	9
2038	1,839,524	627	9
2039	1,869,889	642	9
2040	1,861,797	642	9

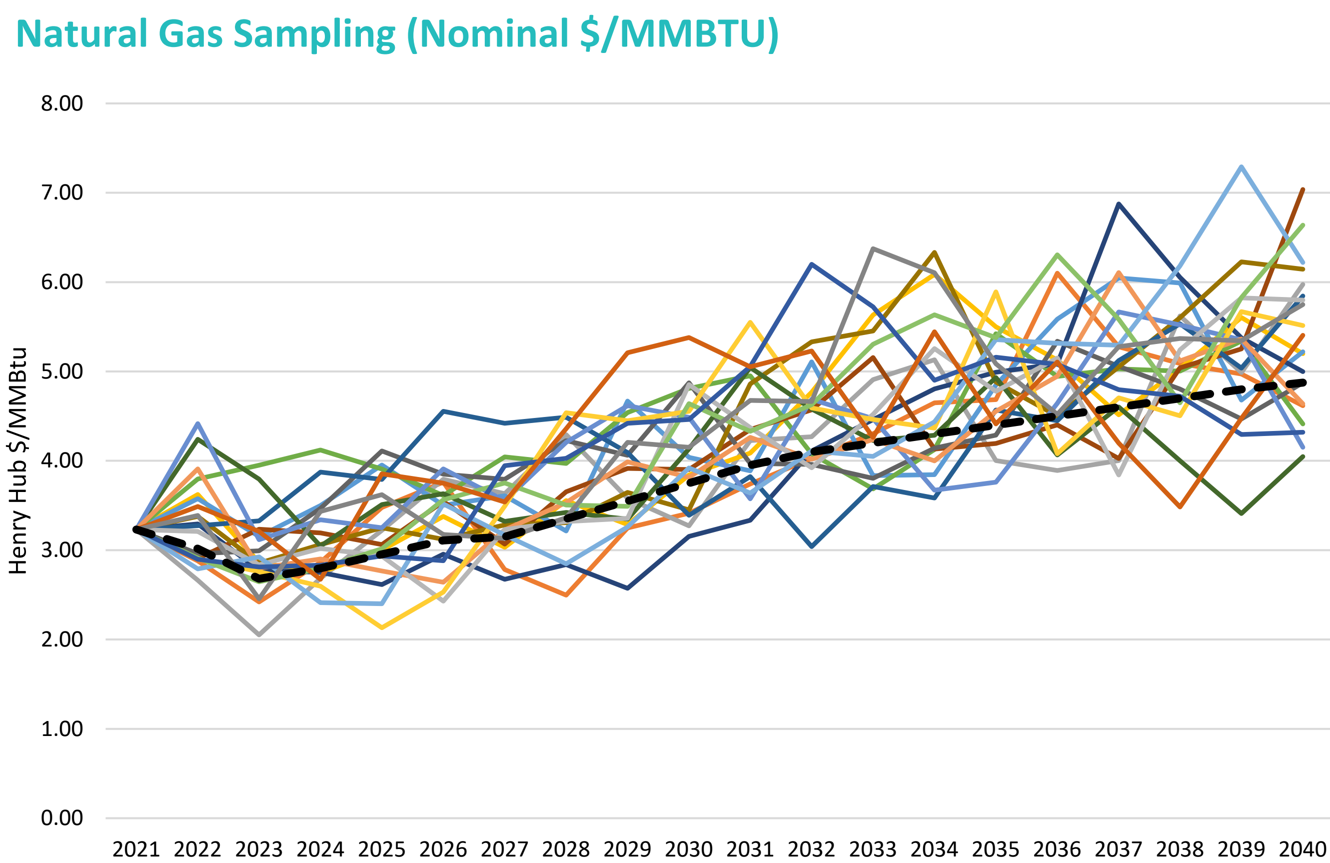
STOCHASTIC RISK ANALYSIS

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.

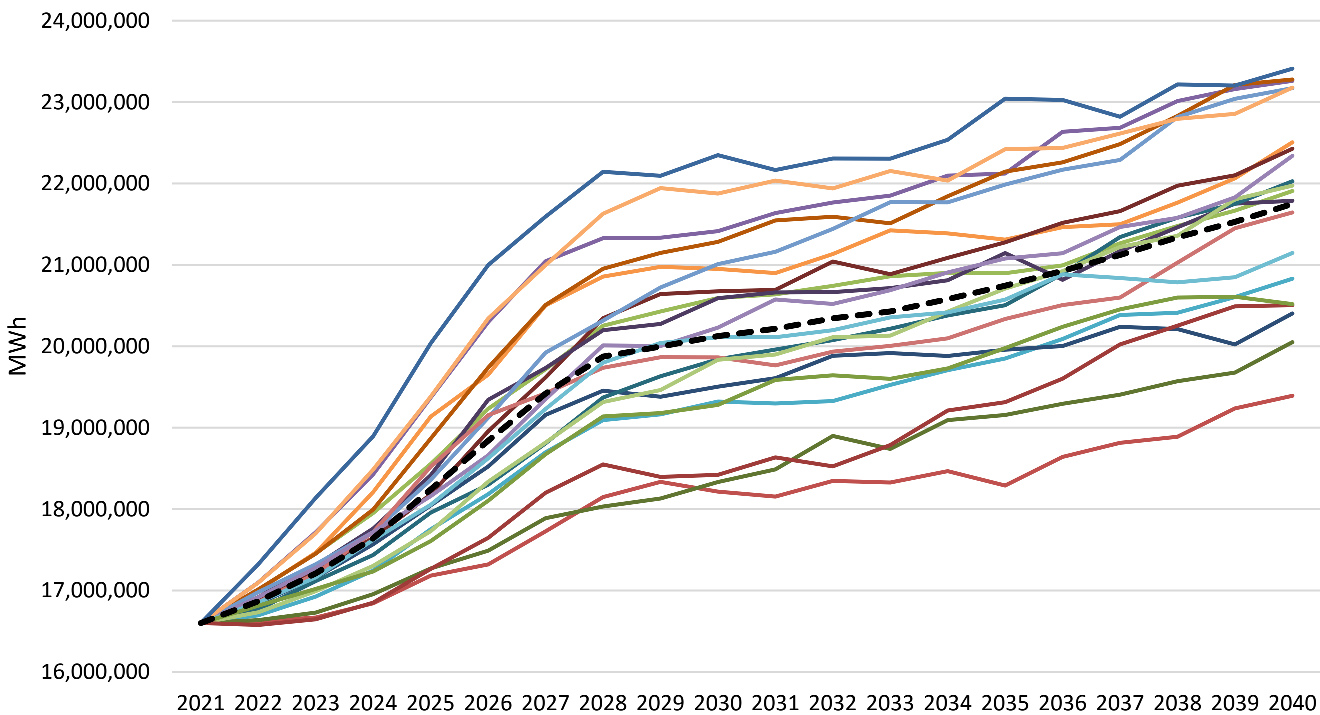
Idaho Power identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Based on the historical Henry Hub natural gas price data for the 1997 to 2020 period, it was determined that natural gas price variance around the trend approximates a log-normal distribution with a year-to-year correlation factor of 0.55. The graph below shows planning case average annual price in the black dashed line and the remaining-colored lines show the 20 different stochastic iterations for Henry Hub gas prices.



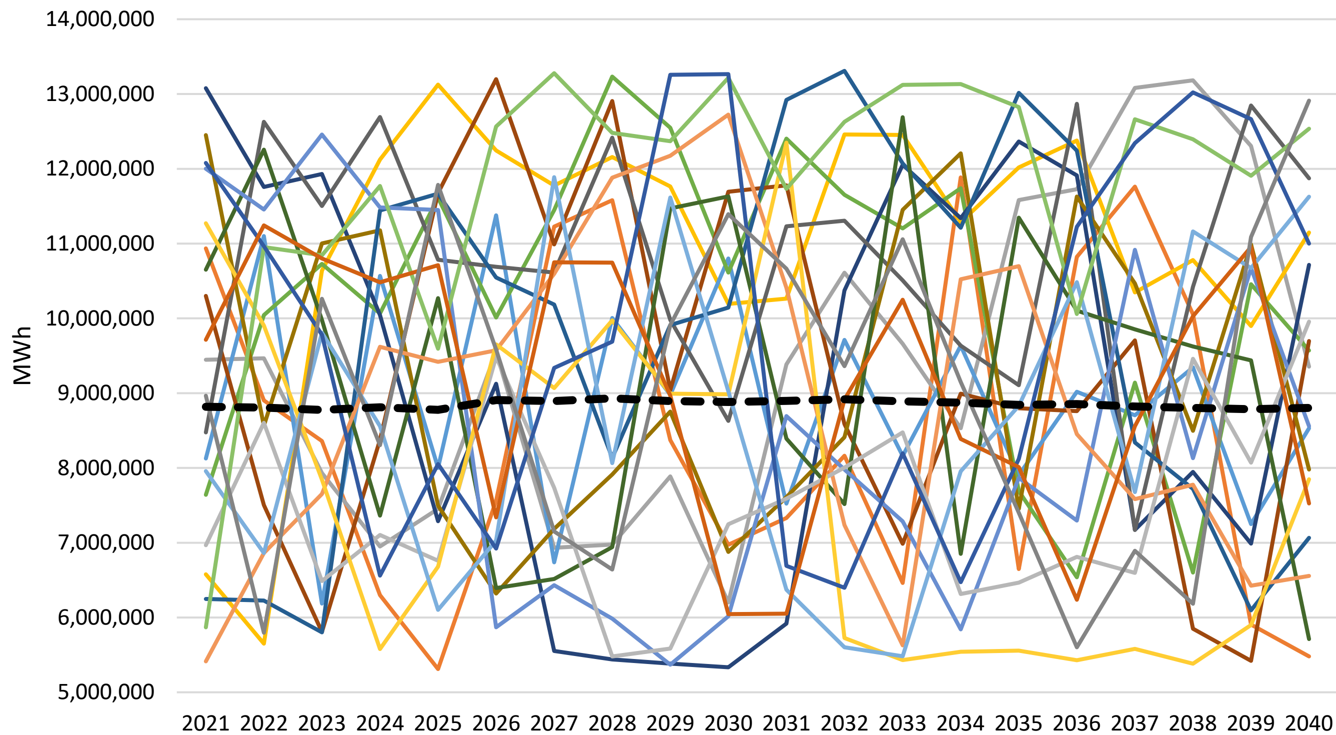
2. *Customer load*—Customer load follows a normal distribution and is adjusted around the planning case load forecast, which is shown as the dashed line in the figure below. To assess the reasonableness of the stochastic error bounds as they relate to customer load, the upper and lower bounds were compared to the load forecast 90/10 error bounds. For both the upper and lower bound, the stochastic values were found to fall slightly outside of the 90/10 bounds which is to be expected. The stochastic process produces 20 scenarios which could be expected to test a larger bound of 95/5.

Customer Load Sampling (Annual MWh)



3. *Hydroelectric variability*—Hydroelectric generation variability was found to approximate a uniform distribution based on the historical generation from the 1951 to 2017 period. Although an unexpected result based on the non-uniform distribution of rainfall across the Snake River Basin, the regulation of streamflow likely explains the difference between rainfall and generation distributions. In addition to the distribution, the historical data also shows a correlation between years of 0.55.

Hydro Generation Sampling (Annual MWh)

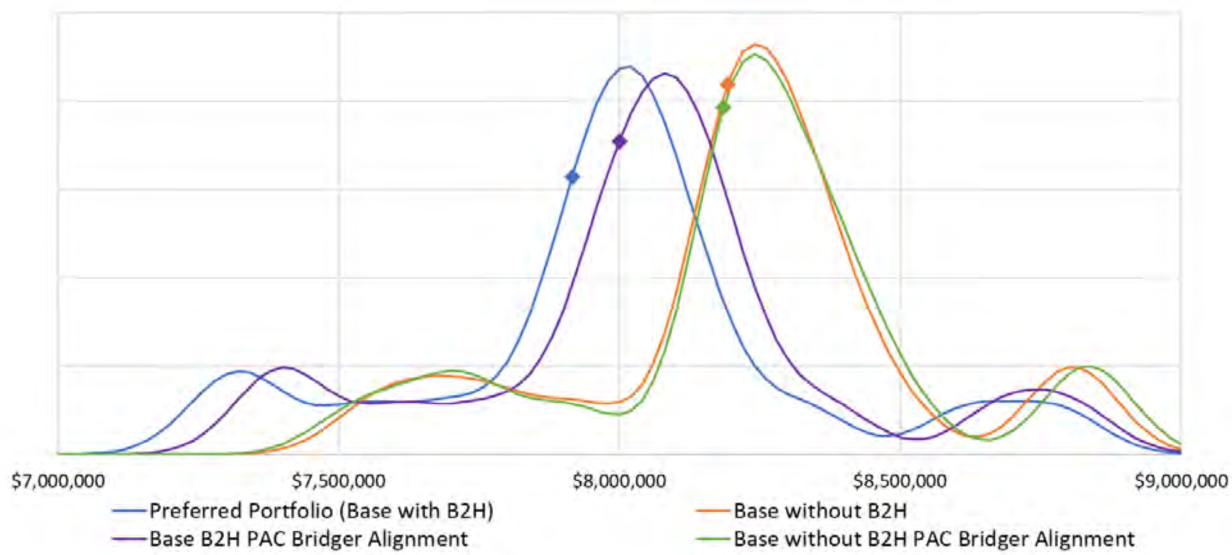


The three selected stochastic variables are key drivers of variability in year-to-year power-supply costs and therefore provide suitable stochastic shocks to allow differentiated results for analysis.

Due to the significant time required to perform the stochastic risk analysis, Idaho Power was limited to performing a maximum of 20 risk iterations. Based on the sample size, the choice was made to use the Latin Hypercube sampling technique over a pure Monte Carlo method. The Latin Hypercube design samples the distribution range with a relatively smaller sample size, allowing a reduction in simulation run times. The Latin Hypercube method does this by sampling at regular intervals across the distribution spectrum. Contrast this to Monte Carlo methods where samples are taken randomly from the distribution range. The random Monte Carlo draw requires far more than 20 iterations to ensure a good distribution of draws. Once the stochastic elements are drawn, Idaho Power then calculated the 20-year NPV portfolio cost for each of the 20 iterations for all evaluated portfolios. The distribution of 20-year NPV portfolio costs for the portfolios are shown in the graph below.

Portfolio Stochastic Analysis, Total Portfolio Cost

NPV Years 2021–2040 ($ x 1,000)



In the figure above, each line represents the likelihood of occurrence by NPV with the diamonds showing the planning conditions NPV. Higher values on the line represent a higher probability of occurrence with values near the horizontal axis representing improbable events. Values that occur toward the left have lower cost while values toward the right have higher cost. As indicated by the peak of the graph being furthest left, the results of the stochastic analysis show that the Preferred Portfolio (Base with B2H) is likely to have the lowest cost given a range of natural gas prices, load forecasts, and hydroelectric generation levels. Next lowest is the Base B2H PAC Bridger Alignment portfolio indicated by the middle peak. Nearly tied as the most expensive options analyzed using stochastic elements are both Base without B2H portfolios regardless of PAC Bridger alignment.

LOSS OF LOAD EXPECTATION

As utilities continue to add more renewable energy to the electric grid, it is becoming more critical to analyze the effect variable energy resources have on system reliability. For the 2021 IRP, Idaho Power utilized the risk-based equations and methodologies described in this section to calculate the contribution to peak of different variable energy resources for the AURORA model and quantitatively analyze the risk associated with the portfolios. The company chose to conduct this study because of the recognition that the output of variable energy resources such as wind and solar change with time (with their hourly output being dependent on a multitude of factors like weather and environmental conditions) and that it is essential to capture and value that variability. Another key factor for conducting this study is that the industry is also attempting to establish a generally accepted method to calculate the contribution to peak of variable energy resources, so it is essential for Idaho Power to adopt and apply these best practices.

Methodology Components

The Loss of Load Probability (LOLP) is the likelihood of the system load exceeding the available generating capacity during a given time period (typically an hour). The LOLP can be calculated by determining the probability that the available generation at any given hour is able to meet the net load during that same hour. The LOLP can be defined as:

$$LOLP = P_i(G_i - L_i)$$

where P_i is the cumulative probability of the available generation required to meet the system demand at hour i, G_i is the available generation required to meet the system demand at hour i, and L_i is the system demand at hour i.

The Loss of Load Expectation (LOLE) is the expected number of days per time period for which the available generation capacity is insufficient to serve the demand at least once per day. The LOLE can be calculated by adding the maximum LOLP from each day for a time period (typically over the course of a year). LOLE can be defined as:

$$LOLE = \sum_{d=1}^{D} max[_{i=1}^{H} (LOLP_i)]$$

where $LOLP_i$ is the LOLP at hour i.

The Effective Load Carrying Capability (ELCC) is a reliability-based metric used to assess the contribution to peak of any given generation unit or power plant. ELCC decomposes an individual generator's contribution to the overall system reliability and is primarily driven by the timing of high LOLP hours. These calculated values were assigned to existing and selectable resources when modeling the different portfolios. To calculate the ELCC of a resource, there are two definitions that should first be stated:

EFOR:	the Equivalent Forced Outage Rate (EFOR) represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs; for example, an EFOR of three percent means a generator is forced off three percent of its running time.
Perfect Generator:	a generation unit whose EFOR value is zero percent, meaning that it is always available and never forced off-line.

The ELCC of a resource is determined by first calculating the perfect generation required to achieve an LOLE of 0.05 days per year with all market purchases set equal to zero. Then, the resource being evaluated is added to the system and the perfect generation required is calculated once again. The ELCC of a given resource will be equal to the difference in the size of the perfect generators from the two runs divided by the resource's nameplate:

$$ELCC = \frac{PG_1 - PG_2}{Resource_{NM}}$$

where PG_1 is the perfect generation required to achieve an LOLE of 0.05 days per year without including the evaluated resource, PG_2 is the perfect generation required to achieve an LOLE of 0.05 days per year with the evaluated resource included, and $Resource_{NM}$ is the nameplate of the evaluated resource.

Modeling Idaho Power's System

Idaho Power created a tool to implement the LOLE methodology and maximize computational efficiency for modeling Idaho Power's existing and potential resource stack. Within this tool, the company's resources were split into three primary categories: dispatchable resources, intermittent resources, and energy limited resources (demand response and storage).

Dispatchable resources were modeled using a monthly outage table that was calculated using their monthly capacity and EFOR. The outage table is comprised of the following four components:

Capacity In:	capacity available to serve load (MW)
Capacity Out:	forced outage capacity (MW)
Individual Probability:	probability that a specific event will occur
Cumulative Probability:	cumulative distribution of the individual probabilities

Dispatchable resources include the Hells Canyon Complex, natural gas plants, Bridger and Valmy coal and various transmission assets with access to the market.

Variable resources (such as wind and solar) were modeled by using four years of historical hourly output data to maintain the relationship between load and renewable generation. Other resources for which Idaho Power does not have direct control over (in reference to their dispatch) were also modeled using four years of historical hourly output data. Examples of these resources include dairy digestors, non-wind and non-solar PURPA projects, run of river hydroelectric plants and geothermal generation. In the model, these variable resources are subtracted from the system adjusted load to produce a net load that is then used in the LOLE calculations.

Because resources such as storage and demand response are dispatched based on the daily peak load shape, Idaho Power devised a separate way to model energy limited resources. The tool begins by sorting the days in a year from high to low based on their net load peak. Starting on the day with the highest net load, a target for each day was set based on the net load peak and the size of the demand response group or storage selection. After verifying that the operating parameters of the demand response portfolio or storage resource are met on that day, the algorithm iterates over each hour of the day and compares the net load with the target. If the net load is above the target, the function will dispatch the MW assigned for that hour. The algorithm will then move to the next day and perform all the checks before it iterates over all the hours again; this is done for every day in each year.

This customization functionality of the LOLE tool allows for a detailed approach to modeling Idaho Power's system. As system needs continue to change, new analysis such as this LOLE tool will be essential in best evaluating the company's highest risk hours (which is of key importance since they will no longer necessarily align with the peak load hour).

ELCC Results

The ELCC of future variable energy resources are dependent upon the order of the resources built before them, making the ELCC calculation of future resources challenging. For the 2021 IRP, Idaho Power adopted the concept of "last-in ELCC" where from the future resources being modeled, only one resource is added at a time. For example, to calculate the ELCC of future solar PV, all the existing resources are modeled and only solar is included in the LOLE tool. This approach will result in an accurate baseline for AURAORA to build the portfolios.

The average ELCC values used in AURORA for future solar PV, wind, demand response, 4-hour storage, 8-hour storage and solar PV plus storage were fed into the model. The table below shows the ELCC for existing and future resources that were used in the AURORA model.

ELCC of Existing Resources		ELCC of Future Resources	
Resource	Average	Resource	Average
PURPA Solar	62.3%	Solar PV	10.2%
Oregon Solar	62.3%	Jackpot Solar	34.0%
PUPRA Wind	15.0%	Wind	11.2%
Elkhorn Wind	15.0%	4-Hour Storage	87.5%
Current Demand Response	17.3%	8-Hour Storage	97.0%
		Solar PV + 4-Hour Storage	97.0%
		Proposed Demand Response	58.5%
		Incremental Demand Response	36.0%

LOLE of Portfolios

To quantitively analyze portfolio reliability, Idaho Power fed portfolio results into the company's LOLE tool, as described in Chapter 10 of the 2021 IRP. Idaho Power utilized a reliability threshold (LOLE) of 0.1 days per year in the 2019 IRP. For the 2021 IRP, Idaho Power is adopting a reliability threshold of 0.05 days per year. The 0.05 (1-in-20) reliability threshold was chosen to 1) account for the extreme weather events that are becoming more frequent in the Northwest, and 2) factor in water availability uncertainty year to year. A poor water year, resulting in reduced hydro generation, can look equivalent to a season-long resource outage. This 0.05 days per year threshold aligns with the reliability threshold used by the Northwest Power & Conservation Council (NWPCC).

The LOLE tool was used to evaluate various portfolios created by AURORA using the four test years, producing an average LOLE for each year of the planning horizon for each of the selected portfolios. A generator with an EFOR of 5% was added to the LOLE tool when the LOLE of a particular year was above the preestablished threshold.

The portfolio reliability results table below shows the portfolio LOLE per year and the additional generation (when needed) that was added to each of the selected portfolios.

Portfolio Reliability Results

	Preferred Portfolio (Base with B2H)		Base without B2H		Base B2H PAC Bridger Alignment		Base without B2H PAC Bridger Alignment		SWIP-North	
Year	LOLE (d/yr)	Additional Gen. (MW)	LOLE (d/yr)	Additional Gen. (MW)	LOLE (d/yr)	Additional Gen. (MW)	LOLE (d/yr)	Additional Gen. (MW)	LOLE (d/yr)	Additional Gen. (MW)
2021	0.1050	0	0.1050	0	0.1050	0	0.1050	0	0.1050	0
2022	0.0594	0	0.0594	0	0.0594	0	0.0594	0	0.0594	0
2023	0.0259	0	0.0259	0	0.0259	0	0.0259	0	0.0259	0
2024	0.0161	0	0.0147	0	0.0149	0	0.0157	0	0.0157	0
2025	0.0072	0	0.0032	0	0.0074	0	0.0034	0	0.0067	0
2026	0.0016	0	0.0075	0	0.0003	0	0.0071	0	0.0013	0
2027	0.0024	0	0.0087	0	0.0006	0	0.0079	0	0.0024	0
2028	0.0025	0	0.0164	0	0.0009	0	0.0066	0	0.0024	0
2029	0.0035	0	0.0188	0	0.0014	0	0.0076	0	0.0034	0
2030	0.0039	0	0.0199	0	0.0014	0	0.0055	0	0.0038	0
2031	0.0056	0	0.0282	0	0.0025	0	0.0103	0	0.0033	0
2032	0.0064	0	0.0324	0	0.0027	0	0.0120	0	0.0046	0
2033	0.0073	0	0.0389	0	0.0026	0	0.0123	0	0.0043	0
2034	0.0049	0	0.0280	0	0.0007	0	0.0042	0	0.0032	0
2035	0.0354	0	0.0494	185	0.0276	0	0.0493	200	0.0190	0
2036	0.0392	0	0.0491	20	0.0361	0	0.0442	45	0.0220	0
2037	0.0495	7	0.0477	40	0.0402	0	0.0506	15	0.0293	0
2038	0.0445	3	0.0386	0	0.0473	0	0.0509	20	0.0293	0
2039	0.0487	15	0.0499	5	0.0492	16	0.0498	20	0.0315	0
2040	0.0496	16	0.0498	10	0.0480	24	0.0511	5	0.0400	0
Total		**41**		**260**		**40**		**305**		**0**

COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

Guideline 1: Substantive Requirements

a. All resources must be evaluated 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 power or gas purchases, transportation, and storage and 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:

Idaho Power considered a range of resource types including renewables (e.g., wind and storage), demand-side management, transmission, market purchases, thermal resources, and energy storage. Each of these resources was included as options in the AURORA capacity expansion modeling.

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 4. Idaho Power Today;* demand-side options are discussed in *Chapter 6. Demand-Side Resources*; and transmission resources are discussed in *Chapter 7. Transmission Planning*.

New resource options including fuel types, technologies, lead times, in-service dates, durations, and locations are described in *Chapter 5. Future Supply-side Generation and Storage Resources*, *Chapter 6. Demand-Side resources*, *Chapter 7. Transmission Planning*, and *Chapter 8. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 8. Planning Period Forecasts* and *Chapter 10. Modeling Analysis and Results*.

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 hydroelectric generation) for resource portfolios are considered in *Chapter 10. Modeling Analysis and Results*. Plant forced outages are modeled in AURORA on a unit basis and are discussed in *Chapter 9 Portfolios*. Risk and uncertainty associated with high natural gas and high carbon cost are discussed in *Chapter 9 Portfolios.*

Additional sources of risk and uncertainty including regional resource adequacy and qualitative risks are discussed in *Chapter 10. Modeling Analysis and Results*.

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. Background*.

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 10. Modeling Analysis and Results*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 10. Modeling Analysis and Results*.

Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1. Background*. 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 11. 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* and *Chapter 3. Climate Change*. The company also evaluated four future scenarios, including rapid electrification, climate change, 100% clean by 2035, and 100% clean by 2045. These are discussed in *Chapter 9. Portfolios*.

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 IRPAC meetings are open to the public. A roster of the IRPAC 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 IRPAC meetings and found throughout the 2021 IRP, the 2021 Load and Sales Forecast and in the 2021 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 posted online a draft 2021 IRP for public review on December 20, 2021. The company requested comments to be provided no later than December 27, 2021.

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 2019 IRP on June 4, 2021 in Order 21-184. The company received an extension on its 2021 IRP and it was filed in December 2021.

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 schedule a public meeting at the OPUC following the December 30, 2021 filing of the 2021 IRP.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

Idaho Power response:

This will be conducted following the filing of this IRP.

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:

This will be conducted following the filing of this IRP.

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 requested and received a waiver of the 2019 IRP update in Order No. 21-184. This activity for the 2021 IRP will occur following the filing of this IRP.

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:

Not applicable to this filling; this activity will be conducted at a later time.

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:

The information in this section is intended to show how the company complied with this guideline.

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 are tested using the Rapid Electrification case as discussed in *Chapter 9. Portfolios*. Stochastic analysis was performed on load (which creates high and low load conditions) and the details of that analysis are contained in the Technical Appendix.

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 8. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Load and Resource Balance, 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 9. 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 5. Future Supply-Side Generation and Storage Resources*.

Demand-side resources are discussed in *Chapter 6. Demand-Side Resources*.

Resource costs are discussed in *Chapter 8. Planning Period Forecasts* 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 and cost-risk tradeoffs are covered in *Chapter 10. Modeling Analysis and Results*

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 8. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in *Chapter 10. Modeling Analysis and Results*.

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 2021 IRP are described in *Chapter 9. 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 10. Modeling Analysis and Results*.

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 10. Modeling Analysis and Results*.

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 10. Modeling Analysis and Results*.

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 11. 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 preferred portfolio including coal-unit exits is discussed in *Chapter 11. 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 the *Executive Summary* and in *Chapter 11. 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 costs (including 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 7. Transmission Planning*. Transportation for natural gas is discussed in *Chapter 8. Planning Period Forecasts*.

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 2021 IRP and is described in *Chapter 6. Demand-Side Resources*.

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 6. Demand-Side Resources*. The load forecast into AURORA includes the reduction to customer sales of all future achievable economic energy efficiency potential. In addition to the baseline energy efficiency potential, the company modeled extra bundles of achievable technical energy efficiency and their costs in the AURORA model.

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 2020 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 6. Demand-Side Resources.*

As part of the 2021 IRP's rigorous examination of the potential for expanded demand response, Idaho Power utilized a Northwest Power and Conservation Council (NWPCC) assessment of DR potential for the Northwest region to determine the DR potential that may be available in Idaho Power's service area. Based on this assessment, Idaho Power estimated 584 MW of DR potential in its service area and concluded that any needed capacity from DR would be shifted to later hours of the day than what the current DR programs were designed for. Efforts to redesign each of Idaho Power's current programs to better align with system needs took place over the summer and early fall of 2021. Based on the results of the analysis, Idaho Power submitted filings with both the IPUC and OPUC to modify the program parameters.

Guideline 8: Environmental Costs

a. Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions.

The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or “costs,” would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as an allowance for credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.

Idaho Power response:

The carbon price forecasts used in the 2021 IRP are found in *Chapter 9. Portfolios*. Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 10. Modeling Analysis and Results*. Emissions for each portfolio are shown in the Technical Appendix.

b. Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.

Idaho Power response:

See *Chapter 9. Portfolios* and *Chapter 10. Modeling Analysis and Results* for discussion on the various scenarios and comparative analysis of the scenarios. The company also evaluated coal unit conversions to natural gas fuel as a compliance alternative in the portfolios.

c. Trigger point analysis: The utility should identify at least one CO2 compliance “turning point” scenario, which, if anticipated now, would lead to, or “trigger” the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio’s expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.

Idaho Power response:

See *Chapter 9. Portfolios* and *Chapter 10. Modeling Analysis and Results* for discussion on the various scenarios and comparative analysis of the scenarios.

d. Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.

Idaho Power response:

The company evaluated "100% Clean by 2035" and "100% Clean by 2045" scenarios. The results of the portfolios are presented in the Technical Appendix.

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 10. Modeling Analysis and Results*. Idaho Power will file the 2021 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 9. Portfolios. A loss of load expectation analysis and regional resource adequacy are discussed in *Chapter 10. Modeling Analysis and Results.*

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 5. Future Supply-Side Generation and Storage Resources* and in *Chapter 8. Planning Period Forecasts*.

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 identifies its proposed acquisition strategy in *Chapter 11. Preferred Portfolio and Action Plan.* Idaho Power's near-term resource procurement strategy is discussed in *Chapter 11. Preferred Portfolio and Action Plan.*

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 2021 IRP's analysis for the flexibility guideline is provided in *Chapter 9. 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 9. 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:

Future supply side resource options are discussed in *Chapter 5. Future Supply Side Generation and Storage Resources*. Future demand-side resource options are discussed in *Chapter 6. Demand-Side Resources*. The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast.

STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2019 IRP

Action Item 1: Jim Bridger Units 1 and 2

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.

Idaho Power response:

The 2021 IRP evaluates early exit dates of Units 1 and 2 compared to conversion to natural gas operations. The company will continue to work with its partner PacifiCorp to develop the terms necessary to allow for early exit or conversion to a non-coal fuel source.

Action Item 2: Solar Hosting Capacity

Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP

Idaho Power response:

Solar-hosting capacity was assessed as a driver of the customer-owned generation forecast and was determined to not materially impact the customer-owned generation forecast. The company will continue to assess the impact of solar hosting capacity in future iterations of the IRP.

Action Item 3: B2H

Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s)

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 7. Transmission Planning*. Modeling design and analysis testing B2H in the 2021 IRP is found in *Chapter 9. Portfolios* and *Chapter 10. Modeling Analysis and Results*. Further details will be provided in Appendix D-Transmission Supplement which is anticipated to be filled in the first quarter of 2022.

Action Item 4: 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 7. Transmission Planning*. Modeling design and analysis testing B2H in the 2021 IRP is found in *Chapter 9. Portfolios* and *Chapter 10. Modeling Analysis and Results*. Further details will be provided in Appendix D-Transmission Supplement which is anticipated to be filled in the first quarter of 2022.

Action Item 5: VER variability and system reliability

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.

Idaho Power response:

The 2020 VER Study was completed, and the results of the study were included in the Regulating Reserve calculations discussed in *Chapter 9. Portfolios.*

Action Item 6: Boardman

Exit Boardman December 31, 2020.

Idaho Power response:

The Boardman power plant ceased operation in October 2020.

Action Item 7: Jim Bridger Units 1 and 2

Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.

Idaho Power response:

The negotiation between the Environmental Protection Agency (EPA), state of Wyoming, and PacifiCorp to resolve Jim Bridger units 1 and 2 compliance with the Federal Clean Air Act Regional Haze (RH) rules is ongoing. On November 15, 2021 Wyoming Governor Gordon issued a notice of intent to sue alleging that EPA failed to perform a nondiscretionary duty under the Clean Air Act when it failed to approve or disapprove Wyoming's RH State Implementation Plan revision for Bridger within the time prescribed by law. On November 16, 2021 the Wyoming Public Service Commission initiated an investigation to determine the effects on rates, generation adequacy, system reliability, and other aspects of operations by the potential discontinuation of operations at Jim Bridger Unit 2 due to the EPA's inaction on the Wyoming Regional Haze State Implementation Plan.

Action Item 8: VER Integration

Conduct a VER Integration Study.

Idaho Power response:

Idaho Power worked in conjunction with a Technical Review Committee (TRC) for the development of the 2020 VER Study and retained E3 to conduct the study. The study was filed with the OPUC in docket UM 1730(6).

Action Item 9: North Valmy Unit 2

Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2

Idaho Power response:

Idaho Power conducted a system reliability analysis to evaluate the timing of exit from Valmy Unit 2. The results of the analysis were filed in IPUC docket IPC-E-21-12 and in OPUC docket LC 74. Additionally, in the 2021 IRP early exit of Unit 2 was evaluated as part of the AURORA capacity expansion modeling, but the AURORA model did not select Unit 2 for exit earlier than 2025, see *Executive Summary. Action Plan* and *Chapter 8. Planning Period Forecasts*.

Action Item 10: Jim Bridger Units 1 and 2

Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.

Idaho Power response:

The 2021 IRP evaluates early exit dates compared to conversion of Units 1 and 2 to natural gas. The company will continue to work with its partner PacifiCorp to develop the terms necessary to allow for early exit or conversion to a non-coal fuel source.

Action Item 11: Jim Bridger Units 1 or 2

Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022

Idaho Power response:

In the 2021 IRP analysis, Jim Bridger units 1 and 2 have been identified for conversion to natural gas operations, with a 2034 exit date.

Action Item 12: Jackpot Solar

Jackpot Solar 120 MW on-line December 2022.

Idaho Power response:

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

Action Item 13: North Valmy Unit 2

Exit Valmy Unit 2 by December 31, 2022.

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

Idaho Power response:

Idaho Power conducted a system reliability analysis to evaluate the timing of exit from Valmy Unit 2. The results of the analysis were filed in IPUC docket IPC-E-21-12 and in OPUC docket LC 74. Additionally, in the 2021 IRP early exit of Unit 2 was evaluated as part of the AURORA capacity expansion modeling, but the AURORA model did not select Unit 2 for exit earlier than 2025, see *Chapter 8. Planning Period Forecasts*.

Action Item 14: Jim Bridger Units 1 or 2

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).

Idaho Power response:

In the 2021 IRP analysis**,** Jim Bridger units 1 and 2 have been identified for conversion to natural gas operations, with a 2034 exit date.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 78

IDAHO POWER COMPANY

Attachment 2

IRP Commitments

December 30, 2021

Reference	Topic	IRP Requirement, Recommendation or Commitment	How the Item is Addressed in the 2021 IRP
Idaho			
Order No. 34959, p. 15	Modeling	Idaho Power commits to explore cost and reliability impacts from reserve shortfalls as part of the 2021 IRP analysis	For the 2021 IRP, Idaho Power is adopting a reliability threshold of 0.05 days per year to better account for extreme weather events that are becoming more frequent, as well as to align with the reliability threshold used by the Northwest Power & Conservation Council (NWPCC). The portfolio reliability analysis results are shown in the Technical Appendix and the amount of additional generation (when needed) that was added to each of the selected portfolios.
Idaho Power's Reply Comments, p. 46	DERs	The Company plans to apply additional value streams for storage technologies in the 2021 IRP.	The Company applied several benefits to storage technologies such as: peak capacity, regulation reserves, spinning reserves, and locational benefits.
Order No. 34959, p. 14	Load and Resource Balance	The Company agrees and commits to providing the L&RB table in future IRPs.	The load and resource balance table is provided in the Technical Appendix.
Order No. 34959, p. 16	QF/Load and Resource Balance	The Company's next IRP will include a sensitivity analysis about wind replacement assumptions and their impacts on resource planning.	The Company performed CSPP wind renewal sensitivity studies in the 2021 IRP as discussed in *Chapter 9. Portfolio.* The base assumption is that 25% of CSPP wind developers will re-power. The Company also performed the CSPP Wind Renewal Low and High scenarios. These scenarios test the 25% renewal assumption by replacing it with 0% and 100% renewal rates. These studies are discussed in Chapter 9. Portfolios.
Order No. 34959, p. 16	Load and Resource Balance	Idaho Power agrees with Staff that market availability alongside transmission capacity should be looked at when determining capacity deficiencies and will review these concepts when developing the L&RB to be included in the 2021 IRP.	For the 2021 IRP, internally set aside transmission capacity needs to have a corresponding reservation on neighboring systems to be considered as firm capacity purchases from markets This in response to the Valmy #2 exit study where the availability of third-party transmission was analyzed. A discussion of transmission included in the L&RB is included in the Chapter 10. Capacity Planning Margin. Regional resource adequacy (market depth) is discussed separately in Chapter 10. Regional Resource Adequacy. Appendix D will also include a discussion on market depth.
Order No. 34959, p. 16	Load and Resource Balance	The Company agrees that contingency reserve requirements necessary as a result of transmission customers should play a role in the L&RB evaluation.	Contingency reserves are part of the planning reserve margin. A discussion of transmission customer contingency reserves will be included in the forthcoming Appendix D transmission supplement.
Staff's Comments, p. 15 and Order No. 34959, p. 16	Load and Resource Balance	In the future the Company will provide better definitions of resource categories and will change the labeling per Staffs recommendation. "Existing EE" to "Energy Efficiency"	Labels in the L&RB were updated to provide clearer definitions.
Order No. 34959, p. 15 and Idaho Power's Reply Comments, p. 57	Load Forecast	Idaho Power agreed that class peak dynamics are important to know and therefore, in response to Staff's recommendation, proposed that class-level AMI data be used to inform assignments of class contribution to system peak	The inclusion, results and methodology used to develop class level impacts to peak using conformed hourly forecast are discussed in Appendix A of 2021 IRP.
Order No. 34959, p. 15 and Idaho Power's Reply Comments, p. 57	Load Forecast	Idaho Power also agreed its future IRPs would analyze class-level peak contribution and include sensitivity or probability bands of its system peak forecast.	See above for peak contribution. In addition, the Company included high and low sensitivity bands around the load forecast are and included in Appendix A of 2021 IRP. These sensitivity bands around the load forecast are guideposts for the stochastic analysis used.
Order No. 34959, p. 18	Load Forecast	Idaho Power acknowledged that customer-generators accounted for one-half of one percent of retail customers when the 2019 IRP was developed but that recent adoption of solar is "relatively strong" in Idaho Power's service territory, and the higher values will be reflected in the 2021 load forecast.	The Company included a decrement to the load forecast for net metered customer generators. Details on methodology are included in Appendix A of 2021 IRP. Notice and discussion in regard was held with stakeholders and Staff's of both Idaho and Oregon during March 11, 2021 IRPAC.

Oregon			
Order No. 21-184, p. 8 and Appendix A, p. 4 and 35	Energy Efficiency	Adopts Staff's recommendation that Idaho Power report on the impact that the Idaho cost evaluation change may have, in conjunction with Idaho Power's obligation to evaluate efficiency potential consistent with Oregon cost assessment methodologies as part of the next IRP and for the Company to do a comprehensive review of Energy Trust of Oregon's efficiency measures from 2018 through 2020, and share the results.	Idaho Power performed a comprehensive review of ETO's piloted efficiency measures from 2018 to 2020. The results were presented to the Company's EEAG in August 2020.
Order No. 21-184, p. 9	Valmy Unit 2	In regards to Valmy Unit 2, we direct Idaho Power to provide the results of the analysis in its 2021 IRP to either confirm the proposed 2022 exit or provide clarification on next steps in the event the early exit is not supported by analysis.	Idaho Power conducted a system reliability analysis to evaluate the timing of exit from Valmy Unit 2. The results of the analysis were filed in IPUC docket IPC-E-21-12 and in OPUC docket LC 74. Additionally, in the 2021 IRP early exit of Unit 2 was evaluated as part of the AURORA capacity expansion modeling, but the AURORA model did not select Unit 2 for exit earlier than 2025, see Chapter 8. Planning Period Forecasts.
Order No. 21-184, p. 10 and Appendix A, p. 12	Jim Bridger Units 1 and 2	Early exit from Jim Bridger Units 1 and 2 We will review the additional analysis and updates on negotiation with PacifiCorp in Idaho Power's 2021 IRP. More information regarding Jim Bridger 1 and 2 exits should be provided in the 2021 IRP, including a reliability impact analysis similar to the one proposed for Valmy	For the 2021 IRP, Idaho Power used AURORA's LTCE model to determine the best Bridger operating option specific to Idaho Power's system subject to the following constraints: •Unit 1—Allowed to exit year-end 2023 or convert to natural gas. If converted to natural gas, the unit will operate through 2034. •Unit 2—Allowed to exit between year-end 2023 and year-end 2026 or convert to natural gas as early as year-end 2023. If converted to natural gas, the unit will operate through 2034. •Unit 3—Can exit no earlier than year-end 2025 and no later than year-end 2034. •Unit 4—Can exit no earlier than year-end 2027 and no later than year-end 2034. The results of the LTCE model indicate that the conversion of units 1 and 2 to natural gas in 2023 is economical. The Preferred Portfolio identifies exits for units 3 and 4 year-end 2025 and 2028, respectively. To ensure the robustness of these modeling outcomes, the company performed a significant number of validation and verification studies around the Bridger conversions and coal exit dates. These validation and verification studies are detailed in Chapter 9.
Order No. 21-184, p. 11 and Appendix A, p. 23	Jim Bridger Units 1 and 2	Update the Commission as soon as it knows the outcome of PacifiCorp's negotiation with the Wyoming DEQ regarding continued use of Jim Bridger Units 1 and 2 without SCR investments.	The negotiation between the Environmental Protection Agency ("EPA"), state of Wyoming, and PacifiCorp to resolve Jim Bridger units 1 and 2 compliance with the Federal Clean Air Act Regional Haze ("RH") rules is ongoing. On November 15, Wyoming Governor Gordon issued a notice of intent to sue alleging that EPA failed to perform a nondiscretionary duty under the Clean Air Act when it failed to approve or disapprove Wyoming's RH State Implementation Plan revision for Bridger within the time prescribed by law. On November 16, the Wyoming Public Service Commission initiated an investigation to determine the effects on rates, generation adequacy, system reliability, and other aspects of operations by the potential discontinuation of operations at Jim Bridger Unit 2 due to the EPA's inaction on the Wyoming Regional Haze State Implementation Plan.

Order No. 21-184, p. 16	B2H	We decline to determine that 20 percent is the appropriate cost contingency for B2H, but expect Idaho Power to explain and support the cost contingency assigned to this project in the 2021 IRP.	A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Evaluating cost risks to ensure cost effectiveness (i.e., a tipping point analysis) is an important consideration when planning for such a project. Chapter 10. Modeling Analysis -Table 10.9 details the cost of the B2H project with 0%, 10%, 20%, and 30% cost contingencies. Utilizing the numbers in Table 10.8 and comparing them to the difference between the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio, the B2H project would have to increase significantly beyond a 30% contingency before the project would no longer be cost-effective.
Order No. 21-184, p. 16	B2H	We expect Idaho Power to analyze closely whether expanding its ownership share from 21 percent, and relying on OATT revenues to offset its additional costs is truly comparable, in terms of risks and financial impacts, to joint ownership. Where differences may exist, we expect that Idaho Power will explain how those risks are mitigated or considered in its analyses.	Idaho Power in the 2021 IRP requests acknowledgement of B2H based on the company owning 45% of the project. This ownership share, which represents a change from Idaho Power's 21% share in the 2019 IRP, is the result of negotiations among Idaho Power, PacifiCorp, and Bonneville Power Administration (BPA). Under such a structure, Idaho Power would absorb BPA's previously assumed ownership share in exchange for BPA entering into a transmission service agreement with Idaho Power. This arrangement, along with many other aspects of B2H, will be detailed in Appendix D, which will be filed during the first quarter of 2022.
Order No. 21-184, p. 17	B2H	Market resource conditions must continue to be reviewed and tested.	Regional Resource Adequacy is discussed in Chapter 10. Modeling Analysis. For the 2021 IRP, Idaho Power reviewed the Pacific Northwest Loads and Resources Study by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.
Order No. 21-184, p. 17	B2H	Idaho Power should update its estimated B2H project costs prior to submitting its 2021 IRP	As part of the 2021 IRP the Company refreshed its overall cost estimate which is included in the B2H costs modeled in the IRP analysis.
Order No. 21-184, p. 18	Demand Response	Adopt Staff's recommendation - DR needs comprehensive review. DR needs to be a priority for Idaho Power, and it needs to carefully review how DR could fill out peak needs, with potentially lower costs than alternative resources.	As part of the 2021 IRP the Company performed a rigorous examination of the potential for expanded demand response, Idaho Power utilized a Northwest Power and Conservation Council (NWPCC) assessment of DR potential for the Northwest region to determine the DR potential that may be available in Idaho Power's service area. Based on this assessment, Idaho Power estimated approximately 580 MW of DR potential in its service area and concluded that any needed capacity from demand response would be shifted to later hours of the day than what the current DR programs were designed for. Based on the results of the analysis, Idaho Power submitted filings with both the IPUC and OPUC to modify the program parameters based on these proposed changes to the programs. This is further discussed in Chapter 6. Demand-Side Resources.
Order No. 21-184, p. 18 and Appendix A, p. 4 and 41	Demand Response	The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.	Based on the results of its comprehensive review, DR was evaluated in the 2021 IRP modeling process by using the 584 MW of DR potential including an estimate of 300 MW of capacity from the modified DR programs. Therefore, a maximum of approximately 280 additional MW of DR (584 MW minus 300 MW, rounded down) was available for selection in the AURORA model when analyzing the future load and resource balance.

Order No. 21-184, p. 18	Load Forecast	We determine that Staff should work with Idaho Power to review the current framework and alternatives, and that Idaho Power should work with Staff and stakeholders to update its methodology. After working with stakeholders, Idaho Power should be prepared to justify its final chosen approach in its next IRP.	The Company held a workshop and received feedback on Load Forecasting models and cross validation tests it proposes to use with stakeholders and the Staff's of Idaho and Oregon Feb 23, 2021. Further the Company up held conference calls and feedback sessions with Idaho Staff April 1, 2021 and April 29, 2021; and Oregon Staff on August 26, 2021 in regards.
Order No. 21-184 - Appendix A, p. 4 and p. 38 and Idaho Power's Final Comments, p. 70	Load Forecast	Include load forecasting improvements with respect to indicator variables and out-of sample testing	Efforts with respect are noted above. In addition, Appendix A of 2021 IRP includes additional discussion.
Order No. 21-184 - Appendix A, p. 4 and 38 and Idaho Power's Final Comments, p. 70	Load Forecast	Present the impacts of the economic recession caused by COVID-19 on long-term load growth	Impacts of COVID-19 was presented to stakeholders and Staff's of both Idaho and Oregon on the March 11, 2021 IRPAC. Narrative discussion is also included in Appendix A of 2021 IRP.
Order No. 21-184 - Appendix A, p. 4 and 38	Load Forecast/Modeling	Address whether the upper and lower bounds on the Company's customer load stochastic risk analysis are wide enough.	The Company did evaluate the stochastic risk bands in preparation of the 2021 IRP and concluded they were reasonable and did not need revision. To assess the reasonableness of the stochastic error bounds as they relate to customer load, the upper and lower bounds were compared to the load forecast 90/10 error bounds. For both the upper and lower bound, the stochastic values were found to fall slightly outside of the 90/10 bounds which is to be expected. The stochastic process produces 20 scenarios which could be expected to test a larger bound of 95/5.
Order No. 21-184, p. 19 and Appendix A, p. 67	QF	In addition to adopting Staff's recommendation to come up with reasonable assumptions through a sensitivity analysis, we direct that, in the next IRP, Idaho Power explain how the sensitivities resulting from the study would affect the IRP's preferred portfolio and action plan if incorporated.	The Company performed CSPP wind renewal sensitivity studies in the 2021 IRP and its discussed in *Chapter 9. Portfolio.* The base assumption is that 25% of CSPP wind developers will re-power. The Company also performed the CSPP Wind Renewal Low and High scenarios. These scenarios test the 25% renewal assumption by replacing it with 0% and 100% renewal rates. These studies are discussed in Chapter 9. Portfolios.
Order No. 21-184, p. 17	DERs	Idaho Power should model renewables plus storage as part of IRP planning.	The 2021 IRP includes renewables plus storage as a supply-side resource option. The various supply-side resources considered in the 2021 IRP are discussed in *Chapter 5. Future Supply-Side Generation and Storage Resources*. The resource attributes for the solar plus storage resource are found in Table 8.4.
Order No. 21-184 - Appendix A, p. 49	DERs	Perform the Company's approved capacity factor approximation method using all the new data that has become available.	With sufficient historical generation data available, the Company was able to calculate the Effective Load Carrying Capability of solar in compliance with Order No. 16-362.
Order No. 21-184 - Appendix A, p. 49	DERs	Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.	The 80 MW cap on battery storage was removed for the 2021 IRP. As evidence, the Company's Preferred Portfolio includes almost 1,700 MW of battery storage resources.
Order No. 21-184 - Appendix A, p. 49	DERs	Model the PTC for wind to the extent it is technically achievable by the Company.	Where feasible, the Company included PTC for future wind resources. Costs of wind resources are provided in *Technical Appendix. Supply-Side Resource Data.*
Order No. 21-184 - Appendix A, p. 49	DERs	Revise its Wyoming cost inputs to include more reasonable cost assumptions.	The Company's cost assumptions are provided in Technical Appendix. Supply-Side Resource Data. Wyoming wind was given a 45% average capacity factor.
Order No. 21-184, p. 7	DERs	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.	Solar hosting capacity was assessed as a driver of the customer-owned generation forecast and was determined to not materially impact the customer-owned generation forecast.
Order No. 21-184 - Appendix A, p. 21	DERs	File the results of each of the VER studies with the Commission once they are complete and notify the LC 74 service list.	Idaho Power worked in conjunction with a Technical Review Committee (TRC) for the development of the 2020 VER Study and retained E3 to conduct the study. The study was filed with the OPUC in docket UM 1730(6).

Order No. 21-184 - Appendix A, p. 4 and 32	Risk	Report qualitative benefits and risks by portfolio in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.	Idaho Power included qualitative risk analysis and its found in Chapter 10. Modeling Analysis - Qualitative Risk Analysis. Table 10.6 shows a Qualitative risk comparison between the portfolios.
Order No. 21-184 - Appendix A, p. 4 and 32	Risk	Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.	In addition to testing the portfolios against high gas and high carbon risk, the Company in collaboration with the IRPAC developed four additional future scenarios to be run for the purpose of risk evaluation: Rapid Electrification, climate change, 100% Clean by 2035 and 100% Clean by 2045. These are discussed in Chapter 9. Portfolios.
Order No. 21-184 - Appendix A, p. 4 and 32	Modeling	Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.	Idaho Power worked with Energy Exemplar, the AURORA software developer to ensure that capacity expansion runs for the 2021 IRP were optimized specifically for Idaho Power's system. The Company also performed model validation and verification tests to ensure the model is operating as expected and to verify that the selected Preferred Portfolio represents a robust optimization of cost and risk. The Company held an AURORA workshop on April 22, 2021 to help stakeholders better understand the AURORA modeling.
Order No. 21-184 - Appendix A, p. 29	Modeling	In the 2021 IRP improve portfolio naming conventions	For the 2021 IRP, the Company developed a branching scenario analysis strategy to ensure that it had reasonably identified an optimal solution specific to its customers. Figure 9.1 details the initial branching evaluation where the company compared AURORA-optimized portfolios for a base scenario (i.e., planning conditions for all key inputs such as load growth, natural gas price, carbon price, etc.) for six potential future portfolios. Figure 9.2 details the additional sensitivities and scenarios.
Idaho Power's Reply Comments, p. 47-48	Modeling	Transmission capacity assumptions (for market purchases and what counts toward planning margin) will be reevaluated in the 2021 IRP.	The determination of the Planning Margin is discussed in *Chapter 9. Portfolios* and in the LOLE methodology is found in the Loss of Load Expectation section of Appendix C—Technical Report. The Planning margin resource type breakdown is shown in Table 9.1
Order No. 21-184 - Appendix A, p.4-5 and p. 43	Other	Provide an update on the Oregon Residential Time-of-Day Pilot Plan, including number of participants, total cost of the pilot since its 2019 launch, and peak capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the Smart Grid Report will be suspended with the Commission approval of DSP guidelines.	In Chapter 6. Demand Size Resources, the Company provides an update on its Oregon TOU offering.
Order No. 21-184 - Appendix A, p. 5 and p. 51	Other	The Company should produce the Climate Change Risk Report referenced in the 2017 IRP acknowledgment order and include it in the next IRP.	The climate change risk report is included as *Chapter 3. Climate Change.* This new chapter of the IRP focuses on identifying climate-related risks, discussing the company's approach to monitoring and mitigating identified risks, and examining climate-related risk considerations in the IRP.