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September 29, 2023

**VIA ELECTRONIC FILING AND U.S. MAIL**

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street SE, Suite 100
Salem, Oregon 97308-1088

**Re: Docket LC 84 – Idaho Power Company's 2023 Integrated Resource Plan ("IRP").**

Attention Filing Center:

Attached for filing in the above-referenced docket is Idaho Power Company's Application and 2023 Integrated Resource Plan, with Appendices A, B and C. Hard copies of this filing will be sent to the Public Utility Commission of Oregon.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachments

**BEFORE THE PUBLIC UTILITY COMMISSION**
**OF OREGON**

**LC 84**

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY'S<br><br>2023 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, 07-047, and 12-013, hereby requests that the Commission issue an order acknowledging the Company's 2023 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 2023 IRP represents 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 2024 to 2043. Using a robust modeling tool called AURORA, resources are selected from a variety of supply- and demand-side options to develop optimal portfolios (or sets of resources) for various future scenarios. To ensure that the modeling results in least-cost, least-risk portfolios, Idaho Power employed verification tests to validate the most economic portfolio under numerous variations of resources and timing and employed separate tests to ensure each portfolio would meet the Company's reliability requirements.

In the 2023 IRP, Idaho Power underscores the critical importance of flexibility and adaptability in resource planning. The Company is managing and planning for substantial growth while operating in a rapidly changing technological, market, and policy landscape. Historically, the biennial development of the IRP has allowed Idaho Power to timely update its long-term resource plan based on changing circumstances. Over the past several years, however, balancing load and resources has become increasingly more dynamic as major planning inputs and assumptions are subject to change in real time. These long-term planning challenges are certainly not unique to Idaho Power, as its utility peers and industry partners are facing the same dual challenges of accelerated demand for clean energy resources and unwavering commitment to provide customers with reliable, low-cost service.

However, several individual uncertainties in this planning cycle are specific to Idaho Power. Due to the increased level of uncertainty surrounding several important near-term decisions, the 2023 IRP has been prepared in a manner intended to provide the flexibility and adaptability necessary to inform decisions as more information becomes known prior to the next planning cycle. A few examples include significant load growth, the timing of the Boardman to Hemingway (B2H) transmission line in-service date, and Idaho Power's potential involvement in the Southwest Intertie Project-North (SWIP-N) project. These, and other planning scenarios, are discussed in greater detail throughout the IRP.


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The importance of flexibility and adaptability in resource planning is a theme throughout the 2023 IRP and apparent in the optimal, least-cost, and least-risk resource build out of the Preferred Portfolio, which tells the story of the Company's substantial forecasted growth. Specifically, the Preferred Portfolio adds 3,325 megawatts ("MW") of solar, 1,800 MW of wind, 1,453 MW of storage (four- and eight-hour batteries, as well as long-duration 100-hour storage), 360 MW of additional energy efficiency (EE), 340 MW of hydrogen (H2), 160 MW of new demand response (DR), and 30 MW of geothermal. Additionally, the Preferred Portfolio includes conversions of multiple coal-fired generation units to natural gas, showing the company exiting coal entirely in 2030 and adding a net total of 261 MW of natural gas via coal conversions through 2043 (reflecting the addition of 967 MW of gas conversions and 706 MW of gas conversion exits, netting 261 MW of additional gas generation).

In total, the Preferred Portfolio—considering both additions and exits—adds 6,888 MW of incremental resource capacity over the next 20 years. To support these resource additions, the Preferred Portfolio also includes the B2H transmission line beginning in July 2026 and three Gateway West ("GWW") transmission line segments phased in from 2029 to 2040.

The Near-Term Action Plan puts an ever finer point on the Company's growth and includes more than a dozen major actions and activities spanning supply- and demand-side resources, transmission and distribution expansion, and regional and customer programs:

- Continue exploring potential participation in the SWIP-N project in 2023-2024;
- Add 100 MW of solar and 96 MW of four-hour storage in 2024;
- Convert Bridger Power Plant ("Bridger") units 1 and 2 from coal to natural gas by summer 2024;
- Add 95 MW of cost-effective EE between 2024 and 2028;
- Explore a 5 MW long-duration storage pilot project between 2024 and 2028;


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- Add 200 MW of solar in 2025;
- Add 227 MW of four-hour storage in 2025;
- Install cost-effective distribution-connected storage between 2025 and 2028;
- Bring B2H online in summer 2026;
- Convert North Valmy Generating Station ("Valmy") units 1 and 2 from coal to natural gas by summer 2026;
- If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources between 2026 and 2028;
- Include 14 MW of capacity associated with the Western Resource Adequacy Program (WRAP) in 2027; and
- Bring the first phase of GWW online (Midpoint–Hemingway #2 500 kilovolt (kV) line, Midpoint–Cedar Hill 500 kV line, and Mayfield substation) in 2028.

The complete 2023 IRP consists of four separate documents: (1) the 2023 Integrated Resource Plan; (2) *Appendix A—Sales and Load Forecast*; (3) *Appendix B—Demand-Side Management Annual Report*; (4) *Appendix C—Technical Report*. In prior IRP cycles, Idaho Power developed a separate *Appendix D—Transmission Supplement*. For the 2023 IRP, the information once contained in this supplement with respect to transmission resources (including B2H) has been moved into the main IRP report. Interested parties may also request a single printed copy of the 2023 IRP by contacting irp@idahopower.com.

## II. IRP GOALS AND ASSUMPTIONS

The primary goals of Idaho Power's 2023 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 (2024-2043); (2) ensure the selected Preferred Portfolio


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balances cost and risk, while including environmental considerations; (3) give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources; and (4) involve the public in the planning process in a meaningful way.

The 2023 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. Over the 20-year forecast period, the Company's peak load is expected to grow by approximately 80 MW per year, or more than 1,500 MW over the next two decades. Continued customer growth is driving demand, and the average annual number of customers Idaho Power serves is expected to increase from nearly 639,000 in 2024 to 855,000 by 2043.

To meet this demand, the AURORA model can select from a variety of supply-side resources, including solar, wind, small modular reactor nuclear power, geothermal, biomass, and battery and pumped hydropower storage, as well as two new technology options for the 2023 IRP: green hydrogen and long-duration storage. Additionally, the model evaluates the cost-effectiveness of converting its remaining coal-fired generation to natural gas and assesses the impact of variability of hydroelectric generation, which will remain the backbone of Idaho Power's system into the future.

The 2023 IRP also examines demand-side management (DSM) programs, which are designed to achieve prudent, cost-effective demand response and energy efficiency. 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 increasingly important to facilitate efficient movement of electricity around the region and to help manage and maximize the use of variable energy resources such as wind and solar. The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants. Transmission is a vital part of the 2023 IRP, with the Preferred Portfolio including B2H as well as three segments of GWW.

The 2023 IRP also models Idaho Power's participation in the Western Resource Adequacy Program ("WRAP"), a regional planning and capacity program that allows for sharing of available resources if a participant experiences a short-term period of resource deficiency. The goal of this program is to maintain reliability across all participants' systems over the course of an operating season in which some participants may experience peak load conditions or extreme weather events and, due to circumstances beyond their control, may need additional support to meet demand.

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 in 12 IRPAC meetings spanning the 16-month period from May 2022 through August 2023. A list of the 2023 IRPAC members can be found in *Appendix C—Technical Report*.

The Company also developed training and educational resources on the long-term planning process and the AURORA model, specifically. Further, the Company maintained an online forum for stakeholders to submit questions and comments and for the Company to provide answers available to the public. 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

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

To ensure that AURORA develops least-cost, reasonable, and defensible portfolios, Idaho Power performed validation and verification tests to confirm the model is operating as expected and producing the most economic portfolio under numerous variations of resources and timing. To verify that AURORA-built resource portfolios meet Idaho Power's reliability requirements, the Company leveraged the Loss of Load Expectation (LOLE) methodology and calculated annual capacity positions to meet a LOLE threshold of 0.1 event-days per year. Details about the validation and verification process can be found in the 2023 IRP, *Chapter 9—Portfolios*, and a discussion of the results can be found in *Chapter 10—Modeling Analysis*. An in-depth discussion of the LOLE calculation process can be found in the LOLE section of *Appendix C—Technical Report*.

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

- Construction costs;
- Fuel costs;
- Operations and Maintenance (O&M) costs;
- Transmission upgrade costs associated with interconnecting new resource options;
- Natural gas pipeline reservation 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; and
- Investment/Production Tax Credits associated with qualifying generation.

In addition, to enhance the risk-evaluation within the IRP, the Company worked with the IRPAC to develop a variety of future scenarios. Idaho Power ultimately used these scenarios to test whether the decisions being made within the Near-Term Action Plan window are robust across multiple futures. The future scenarios developed in consultation with IRPAC include:

- High Prices: High natural gas price and high price on carbon emissions;
- Low Prices: Low natural gas price and zero price on carbon emissions;
- Constrained Storage: Increased storage prices that would result from an assumed lithium shortage;


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- 100% Clean by 2035: All electricity resources must be clean (non-carbon emitting) by 2035;
- 100% Clean by 2045: All electricity resources must be clean (non-carbon emitting) by 2045;
- Additional Large Load: High customer growth scenario;
- New Forecasted PURPA[1] resources: Assumes additional must-take generating resources at set prices consistent with state and federal policy;
- Extreme Weather: Assumes more frequent extreme weather that increases demand for electricity;
- Rapid Electrification: Assumes rapid and substantial movement of individuals and industries to more electrified products and resources, increasing demand for electricity; and
- Load Flattening: Assumes a shift of demand for electricity from Idaho Power's peak hours to lower-demand hours during the day, thereby "flattening" the visual shape of the demand for electricity across the day.

## IV. UPDATES IN THE 2023 IRP

Two notable trends emerged in the 2023 IRP: the vital nature of added transmission and the substantial downward trend in portfolio greenhouse gas emissions. These trends are addressed in full in the IRP, with two transmission projects and the Company's emissions trajectory discussed below.

### *A. <u>Boardman to Hemingway</u>*

Idaho Power's 2023 IRP continues to analyze the addition of the Boardman to Hemingway Transmission Line Project to ensure that it remains a prudent resource. In the

[1] Public Utility Regulatory Policies Act of 1978 (PURPA).



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2023 IRP, the Company evaluated B2H based on the Company owning 45 percent of the project and updated cost estimates as directed by the Commission in Order No. 23-004.

As part of the 2023 IRP, the Company provides an evaluation of B2H compared to portfolios that do not include B2H, as well as several sensitivities of the project related to the project's cost contingency, Mid-Columbia market availability, and project timing. The Preferred Portfolio, which includes B2H coming online in the summer of 2026, is significantly more cost-effective than the alternative portfolio without B2H.

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

The Preferred Portfolio (which includes B2H) is approximately $836 million more cost effective than the alternative portfolio (run under the same modeling conditions) without B2H. For comparison, the 2021 IRP Preferred Portfolio with B2H was $266 million more cost effective than the non-B2H alternative. Stated simply, the inclusion of B2H in the 2023 IRP is more than three times as cost effective as the project was in the 2021 IRP.

There are four primary reasons for the increased benefits associated with B2H from the 2021 IRP to the 2023 IRP:

- Competing IRP resources have also experienced cost increase pressures.
- In the 2021 IRP, the Company modeled the termination of 510 MW of transmission-service related revenue upon the completion of B2H. In the 2023 IRP, following discussions with the transmission customer, Idaho Power is no longer assuming termination of this service. This change resulted in the addition of wheeling revenue related to this service and the adjustment of


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Midpoint West available transmission capacity for determining the GWW transmission trigger levels from resource additions.

- Idaho Power's summer load growth has accelerated in the years directly following B2H in-service, further increasing the cost effectiveness of the project.
- Idaho Power's winter needs, which were not a major consideration in the 2021 IRP, have accelerated due to industrial load growth. The Company's B2H-related asset exchange with PacifiCorp enables 200 MW of additional winter connectivity.

With respect to the timing of B2H, Idaho Power is planning for the project to come online in summer of 2026—consistent with the timing of the B2H online date in the Preferred Portfolio. A summer of 2026 online date is only possible because of the timely receipt of a Certificate of Public Convenience and Necessity in Docket No. PCN 5. This key authorization has allowed the Company to move forward with current activities related to securing rights-of-way and other permitting, activities for which the Company does not control the timeline. As a result, the Company also modeled a November 2026 online date for B2H, finding that that scenario, too, is orders of magnitude more cost effective than the non-B2H alternative scenario.

*B. <u>GWW Phase 1</u>*

In the 2023 IRP, Idaho Power has identified the need for multiple GWW phases within the 20-year planning window. The first GWW phase, which falls within the Near-Term Action Plan window, is the Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield 500-kV substation, which will collectively relieve Idaho Power's constrained transmission system between the Magic Valley in south-central Idaho and the Treasure Valley



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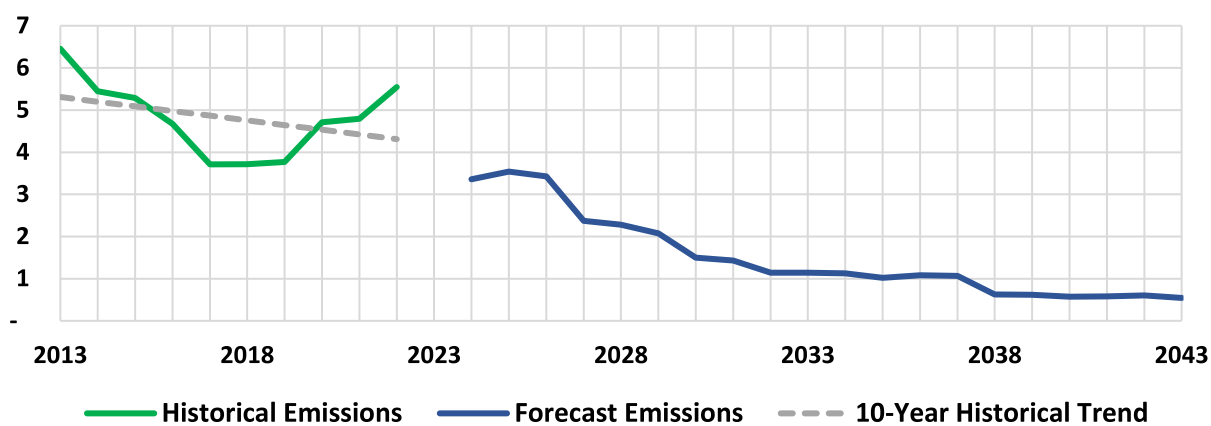
in southwestern Idaho. There were no GWW phases identified for inclusion in the Preferred Portfolio of the 2021 IRP, but that has changed in the 2023 IRP primarily because of the following considerations: (1) a significant increase in Idaho Power's near-term load forecast; and (2) continuation of tax credits associated with wind and solar resources.

With respect to the first consideration, Idaho Power's larger near-term load forecast results in the need for more generation resources. As a result, AURORA is selecting large amounts of cost-effective renewable resources—and GWW will be distinctly suited to bring that electricity to load centers. Similarly, the continuation of tax credits makes renewables more cost-effective in the model, thereby adding more renewables and making GWW even more necessary to enable delivery of the additional renewables.

*C. Reduction in Emissions*

Since the 2021 IRP, Idaho Power has taken significant steps toward reducing carbon emissions, which are detailed further in the 2023 IRP, *Chapter 3—Clean Energy & Climate Change*. These steps include the conversion of all four Bridger units and both Valmy units from coal to natural gas operations, as well as significant additions of clean resources, such as solar, wind, and storage. Forecasted emissions through the IRP time horizon—as demonstrated in the graph below—show a continued and substantial downward trend.

**Total $CO_2$ Emissions (Million Metric Tons)**



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## V. DEVELOPMENT OF THE PREFERRED PORTFOLIO

A fundamental goal of the IRP process is to identify an optimal, 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 2024 to 2043 planning period.

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

- With and without the B2H project;
- With and without different phases of the GWW project; and
- With and without specific Valmy Unit 1 and Unit 2 natural gas conversion assumptions.

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

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

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


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Based on comprehensive analysis, Idaho Power selected its Preferred Portfolio, which is identified in the 2023 IRP as "Valmy 1 & 2", referring to the portfolio's conversion of both Valmy units from coal to natural gas. This Preferred Portfolio, which includes B2H in the summer of 2026, is the least-cost, least-risk option that incorporates positive changes toward clean, low-cost resources without compromising system reliability.

## VI. ACTION PLAN (2024-2028)

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

***Actions Taken Prior to the 2023 IRP—Not for Regulatory Acknowledgment***

- 100 MW of solar and 96 MW of four-hour storage added in 2024 (resources selected through Requests for Proposals [RFP])[2]
- Conversion of Bridger units 1 and 2 from coal to natural gas by summer 2024 (conversions scheduled to occur by summer of 2024)

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[2] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity to Acquire Resources to be Online by 2024 and for Approval of a Power Purchased Agreement with Franklin Solar LLC,* Case No. IPC-E-23-05, IPUC Order No. 35900 (Aug. 23, 2023); *In the Matter of Idaho Power Company Application for Approval of 2026 All-Source Request for Proposals to Meet 2026 Capacity Resource Need*, OPUC Docket No. UM 2255, Idaho Power Company's Notice of Exception under OAR 860-089-0100 (Feb. 17, 2023); *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity to Acquire Resources to be Online in Both 2024 and 2025 and for Approval of an Energy Storage Agreement with Kuna BESS LLC*, Case No. IPC-E-23-20, Idaho Power's Application (May 26, 2023); OPUC Docket No. UM 2255, Idaho Power Company's Notice of Exception under OAR 860-089-0100 (May 26, 2023).

- 95 MW of additional cost-effective EE between 2024 and 2028 (added EE identified in Idaho Power's *2022 Energy Efficiency Potential Study*)
- 200 MW of solar added in 2025 (executed contract for clean energy customer resource)[3]
- 227 MW of four-hour storage added in 2025 (resources selected from the 2022 RFP)[4]

***2023 IRP Decisions for Acknowledgment***

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

Below is a chronological listing of the 2023 IRP's Action Plan items through 2028:

**Near-Term Action Plan (2024–2028)**

| Year | Action |
|---|---|
| 2023–2024 | Continue exploring potential participation in the SWIP-N project |
| 2024 | Add 100 MW of solar and 96 MW of four-hour storage |
| Summer 2024 | Convert Bridger units 1 and 2 from coal to natural gas |
| 2024-2028 | Add 95 MW of cost-effective EE between 2024 and 2028 |
| 2024-2028 | Explore a 5 MW long-duration storage pilot project |
| 2025 | Add 200 MW of solar |

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[3] *In the Matter of Idaho Power Company's Application for Approval of a Power Purchase Agreement with Pleasant Valley Solar, LLC.*, Case No. IPC-E-22-29, IPUC Order No. 35739 (Apr. 12, 2023); *In the Matter of Idaho Power Company Application for Waiver of Competitive Bidding Rules*, OPUC Docket No. UM 2226, Order No. 22-082 (Mar. 11, 2022).
[4] Case No. IPC-E-23-20, Idaho Power's Application (May 26, 2023); OPUC Docket No. UM 2255, Idaho Power Company's Notice of Exception under OAR 860-089-0100 (May 26, 2023).
[5] OPUC Docket No. UM 2255, Idaho Power's Application (Sep. 15, 2022).

| Year | Action |
|---|---|
| 2025 | Add 227 MW of four-hour storage |
| 2025-2028 | Install cost effective distribution-connected storage |
| Summer 2026 | Bring B2H online |
| Summer 2026 | Convert Valmy units 1 and 2 from coal to natural gas |
| 2026-2028 | If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources |
| 2027 | Include 14 MW of capacity associated with the Western Resource Adequacy Program |
| 2028 | Bring the first phase of Gateway West online (Midpoint–Hemingway #2 500 kV line, Midpoint–Cedar Hill 500 kV line, and Mayfield substation) |

## VII. COMPLIANCE WITH ORDER NO. 23-004

In its acknowledgment of Idaho Power's 2021 IRP in Order No. 23-004, the Commission directed Idaho Power to provide additional analysis and/or discussion of 26 items in its 2023 IRP.[6] A table showing each of the Commission's directives, and a discussion of the Company's compliance, is included as Attachment 2 to the Application.

Three of the Commission's directives focus on particularly complex issues and warrant additional discussion in this Application. These issues are: (1) conversion of Bridger units 1 and 2 from coal to natural gas operations, (2) the total cost and associated swaps and investments of B2H, and (3) market prices and price volatility.

*First*, the Commission directed Idaho Power to plan and coordinate with PacifiCorp and regulators for conversion of Bridger units 1 and 2 to natural gas operations with a target conversion date before the summer peak of 2024, and target exit date of 2034.[7] Idaho Power coordinated with PacifiCorp and regulators, and the Bridger units 1 and 2 will be converted to natural gas by the summer of 2024 with an exit date of 2037.

*Second,* the Commission asked Idaho Power to produce a fresh, rigorous estimate of

[6] *In the Matter of Idaho Power Company, 2021 Integrated Resource Plan*, OPUC Docket No. LC 78, Order No. 23-004 at 1, Appendix A at 39-41 (Jan. 13, 2023).
[7] Order No. 23-004, Appendix A at 8.

the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and modeling cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions.[8] Idaho Power provided the total cost of B2H-related swaps and investments, breaking the total down by component, and disclosing all data and assumptions for each estimated component cost in Docket No. PCN 5 to support procurement actions.[9] Idaho Power subsequently updated total B2H cost estimates in September 2023 for this IRP, which resulted in B2H showing increased value. Specifically, the Preferred Portfolio is approximately $836 million more cost effective than the alternative portfolio without B2H.

*Third,* the Commission directed Idaho Power to work with stakeholders and demonstrate the impact of extremely high wholesale electricity prices and decreased liquidity on resource selection in the 2023 IRP, as well as provide insight into volatility and need.[10] Idaho Power worked with members of IRPAC to change its stochastic analysis to help incorporate a greater range of wholesale electricity prices derived from modeled periods of decreased liquidity in wholesale markets. The changes to the stochastic analysis generated

[8] Order No. 23-004, Appendix A at 19.
[9] *In the Matter of Idaho Power Company, Petition for Certificate of Public Convenience and Necessity*, OPUC Docket No. PCN 5, Order No. 23-225 at 9, 27-28 (June 29, 2023) (regarding Idaho Power's compliance with its rules governing estimated and forecasted costs, OAR 860-025-0030(2)(d), the Commission found that "[o]ver the course of the proceeding, Idaho Power provided all information required by rule in the proceeding, which commenced just days after we adopted new rules in September 2022. As Staff explains in its rebuttal testimony, Idaho Power provided additional information to comply with our rules during the discovery process and that information was included in testimony that enabled us to thoroughly review Idaho Power's proposal.") ("Idaho Power's petition and testimony included detailed information regarding the anticipated costs for the B2H project. These costs have been updated as its design packages progressed and as the company learned new information."); *see also* Idaho Power's Supplemental Direct Testimony of Lindsay Barretto (Idaho Power/301 (Boardman to Hemingway Cost Estimates)) (Dec. 30, 2022) (Confidential).
[10] Order No. 23-004, Appendix A at 19.

a wide range of electricity prices and their influence on portfolio cost can be found in Appendix C of the 2023 IRP.

## VIII. 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 2023 IRP and finding that the 2023 IRP meets both the procedural and substantive requirements of Order Nos. 89-507, 07-002, 07-047, and 12-013.

DATED this 29th day of September 2023.

**McDowell Rackner Gibson PC**

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Attorneys for Idaho Power Company

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 84

IDAHO POWER COMPANY

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**Attachment 1**

2023 Integrated Resource Plan

September 29, 2023

# BUILDING OUR FUTURE

September 2023

# IRP
## INTEGRATED RESOURCE PLAN

IDAHO POWER®

## SAFE HARBOR STATEMENT

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# GLOSSARY OF ACRONYMS

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

akW—Average Kilowatt

aMW—Average Megawatt

ASHP—Air-Source Heat Pump

ATC—Available Transfer Capacity

B2H—Boardman to Hemingway

BAA—Balancing Authority Area

BESS—Battery Energy Storage System

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CAISO—California Independent System Operator

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

CEYW—Clean Energy Your Way

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CO2—Carbon Dioxide

CPCN—Certificate of Public Convenience and Necessity

CPP—Critical Peak Pricing

CSPP—Cogeneration and Small-Power Production

CWA—Clean Water Act of 1972

DOE—Department of Energy

DPO—Draft Proposed Order

DR—Demand Response

DSM—Demand-Side Management

DSP—Distribution System Planning

EE—Energy Efficiency

EFSC—Energy Facility Siting Council

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

ELCC—Effective Load Carrying Capability

ELR—Energy Limited Resource

EPA—Environmental Protection Agency

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

NOx—Nitrogen Oxide
NPV—Net Present Value
O&M—Operations and Maintenance
ODOE—Oregon Department of Energy
OPUC—Public Utility Commission of Oregon
PCA—Power Cost Adjustment
PPA—Power Purchase Agreement
PRM—Planning Reserve Margin
PTC—Production Tax Credit
PURPA—Public Utility Regulatory Policies Act of 1978
PV—Photovoltaic
QF—Qualifying Facility
RCAT—Reliability and Capacity Assessment Tool
REC—Renewable Energy Certificate
RFA—Request for Amendment
RFP—Request for Proposal
ROD—Record of Decision
ROR—Run-of-River
RPS—Renewable Portfolio Standard
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SIP—State Implementation Plan
SMR—Small Modular Reactor
SNOWIE—Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment
SRBA—Snake River Basin Adjudication
SWIP-N—Southwest Intertie Project-North
T&D—Transmission and Distribution
TOU—Time-of-Use
TRC—Total Resource Cost
TRM—Transmission Reliability Margin
UCT—Utility Cost Test
VER—Variable Energy Resource
WECC—Western Electricity Coordinating Council
WMP—Wildfire Mitigation Plan
WPP—Western Power Pool
WRAP—Western Resource Adequacy Program

# EXECUTIVE SUMMARY

## Introduction

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

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

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

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

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

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

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

## IRP Methodology Improvements

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

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

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

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

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

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

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

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

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

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

## Portfolio Analysis Overview

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

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

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

- With and without the B2H project

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

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

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

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

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

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

## 2023 Preferred Portfolio

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

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

**Table 1.1 Preferred Portfolio additions and coal exits (MW)**

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

## Preferred Portfolio Changes from the 2021 IRP

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

**Table 1.2 2023 IRP comparison to the 2021 IRP**

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

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

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

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

## Near-Term Action Plan (2024–2028)

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

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

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

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

### 2023 IRP Decisions for Acknowledgment

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

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

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

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

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

## Valmy Unit Conversions and Exits

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

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

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

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

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

## Bridger Unit Conversions and Exits

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

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

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

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

## Boardman to Hemingway

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

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

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

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

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

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

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

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

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

## Gateway West Phase 1

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

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

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

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

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

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

## Southwest Intertie Project-North

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

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

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

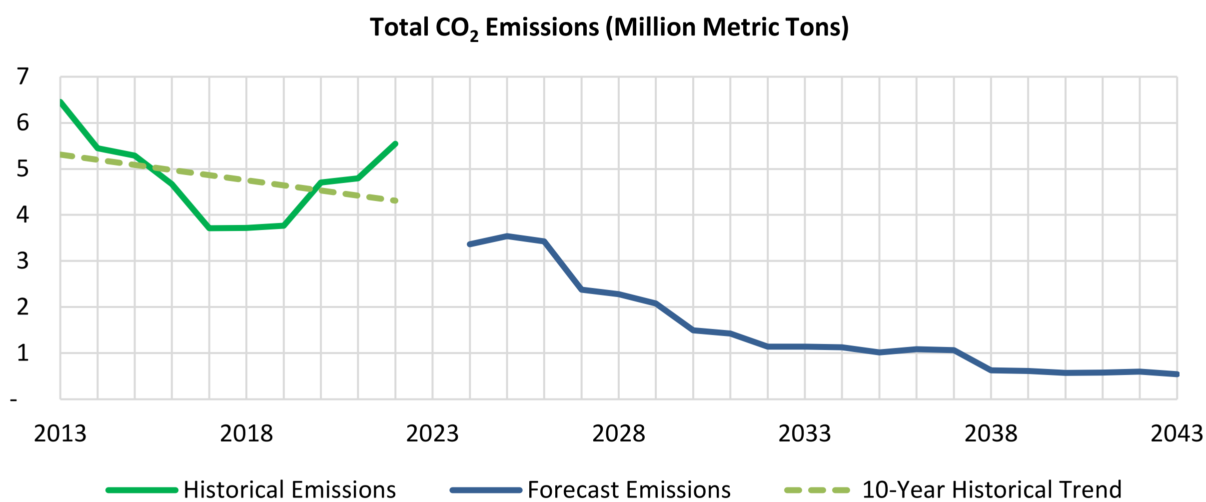
[4] ISO-Board-Approved-2022-2023-Transmission-Plan.pdf (caiso.com).

## Historical and Forecasted Emissions

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

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

**Table 1.4 Historical and forecasted emissions**



# 1. BACKGROUND

## Integrated Resource Plan

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

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

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

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

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

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

## Public Advisory Process

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

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

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

## IRP Methodology

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

### *Cost*

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

### *Risk*

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

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

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

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

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

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

### Modeling

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

### Validation and Verification

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

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

### Reliability

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

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

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

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

## Energy Risk Management Policy

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

# 2. POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

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

## Federal Policy & Activities

### *Hydroelectric Relicensing*

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

Hells Canyon Dam.

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

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

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

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

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

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

Relicensing activities included the following:

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

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

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

### *Recent Executive Orders*

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

### *Inflation Reduction Act*

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

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

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

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

### Clean Power Plan

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

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

### Cross-State Air Pollution Rule

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

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

### Wyoming Round 1 Regional Haze Compliance

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

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

### *Public Utility Regulatory Policies Act*

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

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

## Idaho Policy & Activities

### *Idaho Strategic Energy Alliance*

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

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

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

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

### *Idaho Energy Landscape*

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

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

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

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

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

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

### Idaho Water Issues

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Oregon Policy & Activities

### *State of Oregon 2022 Biennial Energy Report*

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

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

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

### *Oregon Renewable Portfolio Standard and Emissions Reduction Requirements*

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

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

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

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

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

The State of Idaho does not currently have an RPS.

### *Oregon Community Solar Program*

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

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

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

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

## Regional Policies & Activities

### *Western Resource Adequacy Program*

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

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

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

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

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

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

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

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

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

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

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

# 3. CLEAN ENERGY & CLIMATE CHANGE

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

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

## Climate Change Mitigation

### *A Cleaner Energy Mix*

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

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

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

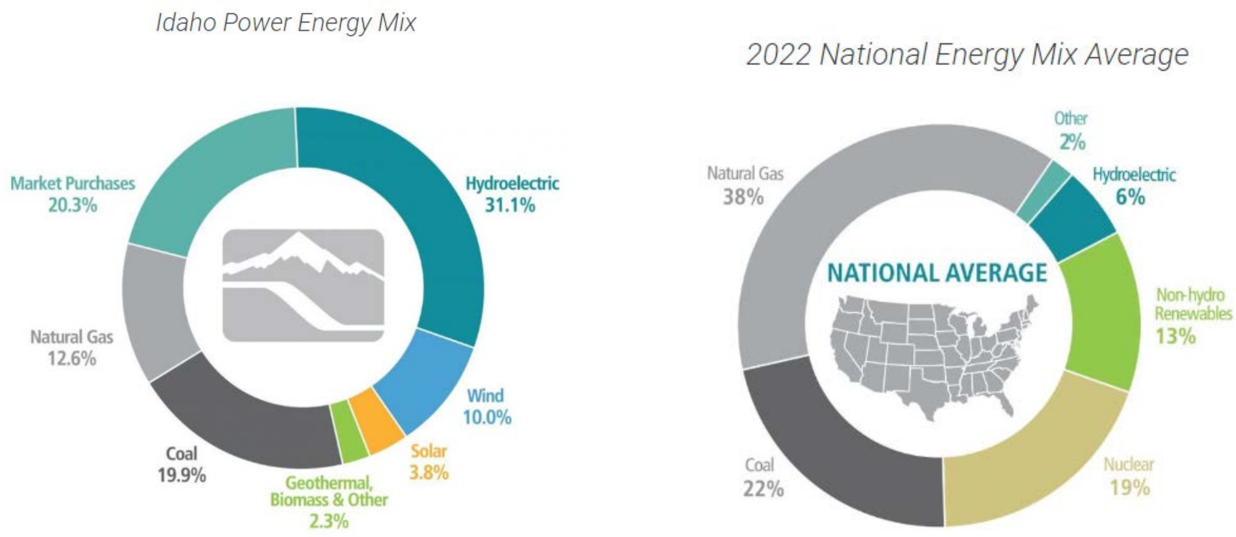


**Figure 3.1 Idaho Power's 2022 energy mix compared to the national average**

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

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

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

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

## *Clean Energy Your Way*

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

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

CEYW includes three options for customers:

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

### Clean Energy Your Way—Flexible

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

### Clean Energy Your Way—Subscription

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

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

### Clean Energy Your Way—Construction

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

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

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

### *Idaho Power Carbon Emissions*

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

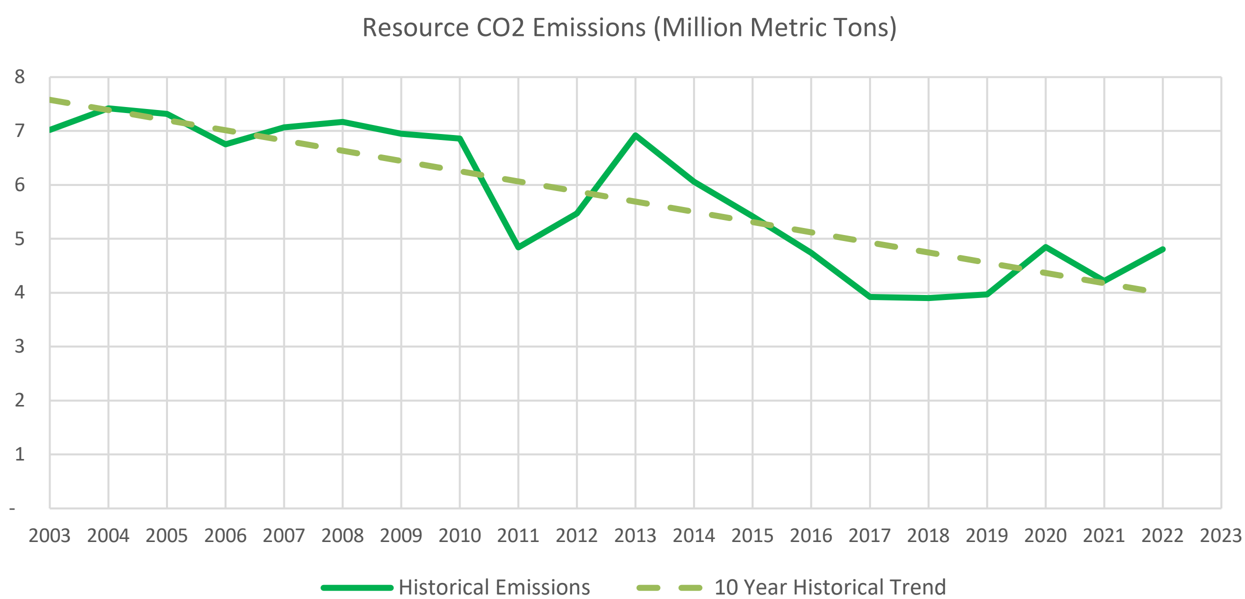


**Figure 3.2 Estimated Idaho Power $CO_2$ emissions**

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

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

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

## Climate Change Adaptation

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

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

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

## Risk Identification and Management

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

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

[19] nca2018.globalchange.gov/.

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

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

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

### Weather Risk

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

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

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

### Wildfire Risk

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

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

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

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

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

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

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

### Water and Hydropower Generation Risk

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

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

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

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

### Policy Risk

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

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

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

## Modeling Climate Risks in the IRP

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

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

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

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

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

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

# 4. IDAHO POWER TODAY

## Customer Load and Growth

Residential construction growth in southern Idaho.

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

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

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

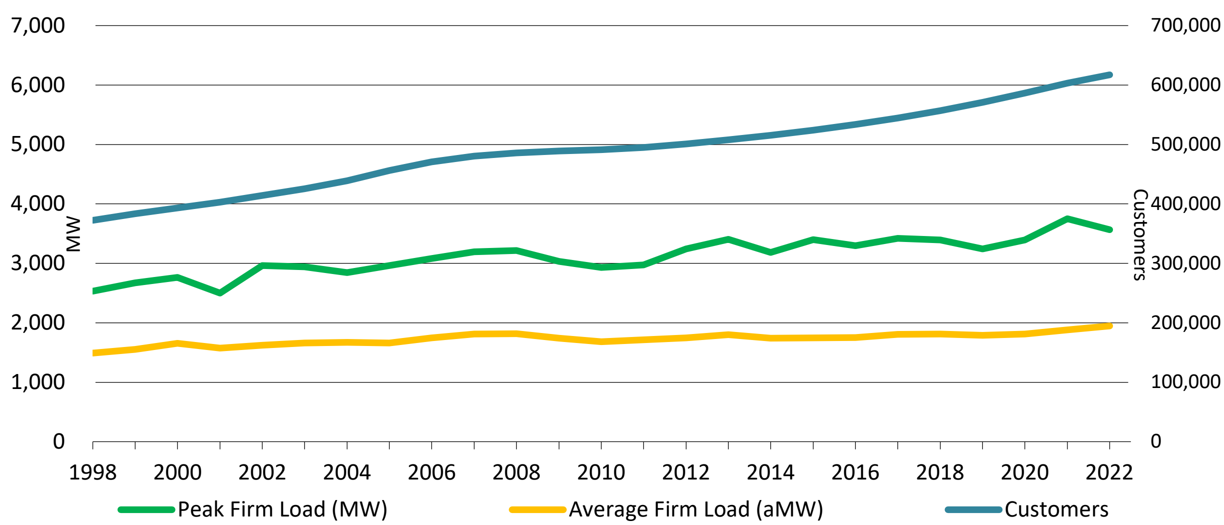


**Figure 4.1 Historical load and customer data**

**Table 4.1 Historical load and customer data**

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

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

## 2022 Energy Sources

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

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

## Existing Supply-Side Resources

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

**Table 4.2 Existing resources**

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

*Capacity as reported in FAC-008 Normal Ratings

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

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

## *Hydroelectric Facilities*

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

### Hells Canyon Complex

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

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

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

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

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

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

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

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

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

### Upper Snake and Mid-Snake Projects

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

### Water-Lease Agreements

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

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

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

### Cloud Seeding

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

Cloud seeding ground generator.

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

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

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

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

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

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

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

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

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

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

## Coal Facilities

### Jim Bridger

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

### North Valmy

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

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

## Natural Gas Facilities and Diesel Units

### Bennett Mountain

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

### Danskin

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

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[25] MW nameplate = net dependable capacity.

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

### Langley Gulch

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

### Diesel

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

## Battery Energy Storage Systems

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

### Hemingway BESS

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

### Black Mesa BESS

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

### Distribution-Connected Storage

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

### Franklin BESS

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

### Happy Valley BESS

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

## *Customer Generation Service*

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

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

**Table 4.3 Customer generation service customer count as of August 2023**

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

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

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

[1]Total may not sum due to rounding.

## Public Utility Regulatory Policies Act

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

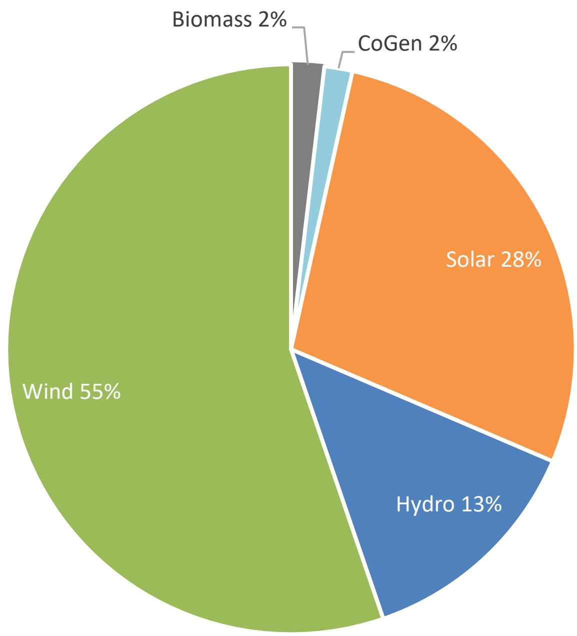



**Figure 4.2 PURPA contracts by resource type**

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

## Non-PURPA Power Purchase Agreements

### Elkhorn Wind

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

### Raft River Energy

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

### Neal Hot Springs

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

### Jackpot Solar

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

### Black Mesa Solar

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

### Franklin Solar

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

### Kuna Storage

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

#### Clatskanie Energy Exchange

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

### *Power Market Purchases and Sales*

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

#### Transmission Import Rights

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

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

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

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

# 5. FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

## Generation Resources


Hemingway Storage.

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

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

## Resource Contribution to Peak

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

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

[27] atb.nrel.gov/.

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

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

## Renewable Resources

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

### *Hydroelectric*

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

### *Solar*

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

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

### *Targeted Grid Storage*

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

**Table 5.1 Targeted grid storage projects**

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

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

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

### *Geothermal*

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

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

### *Wind*

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

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

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

### *Biomass*

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

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

## Thermal Resources

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

### *Natural Gas Resources*

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

#### Simple-Cycle Combustion Turbines

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

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

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

#### Combined-Cycle Combustion Turbines

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

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

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

### Reciprocating Internal Combustion Engines

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

### Combined Heat and Power

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

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

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

### Coal Conversion to Natural Gas

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

### Jim Bridger Coal to Natural Gas Conversion

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

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

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

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

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

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

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

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

#### *North Valmy Coal to Natural Gas Conversion*

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

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

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

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

### Green Hydrogen

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

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

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

### Nuclear Resources

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

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

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

### Coal Resources

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

## Storage Resources

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

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

### *Battery Storage*

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

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

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

### *Pumped Hydro Storage*

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

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

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

### *Multi-Day Storage*

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

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

# 6. DEMAND-SIDE RESOURCES

## Demand-Side Management Program Overview

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

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

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

## Energy Efficiency Forecasting—Energy Efficiency Potential Assessment

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

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

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

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

2. *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the energy efficiency potential study, the contractor applied the UCT for cost-effectiveness, which compares lifetime energy and capacity benefits to the cost of the program. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and adopt every cost-effective and applicable measure.

3. *Achievable*—Achievable potential considers market adoption, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential estimates a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market-adoption factors to the cost-effective potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

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

## Energy Efficiency Modeling

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

### *Technically Achievable Supply Curve Bundling*

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

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

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

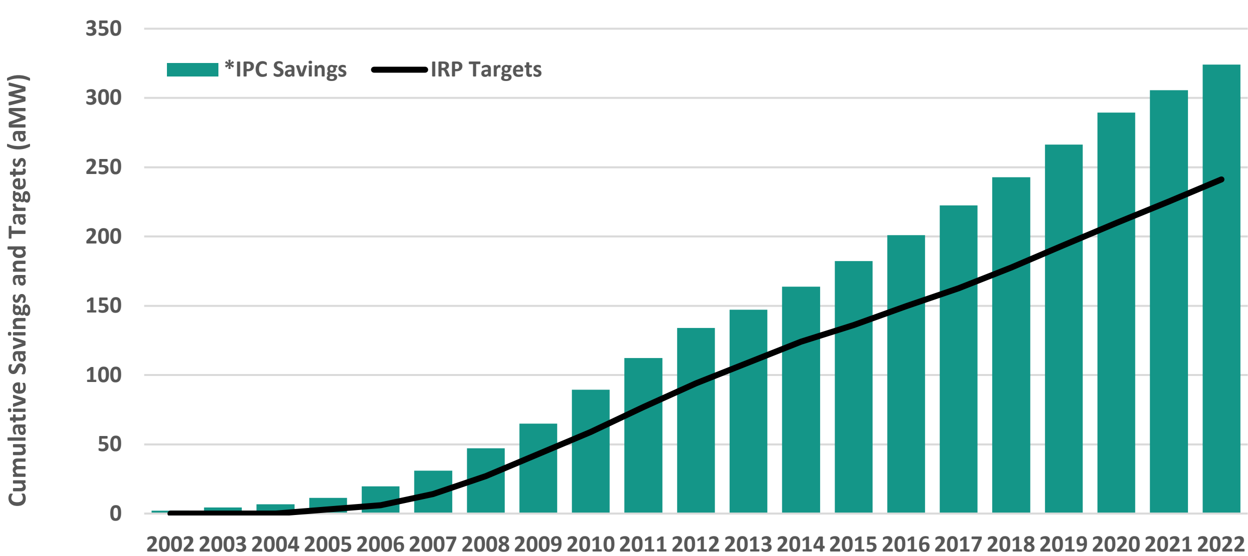
**Table 6.1 Energy efficiency bundles average annual resource potential and average levelized cost**

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

## DSM Program Performance and Reliability

### *Energy Efficiency Performance*

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




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

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

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

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

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

* NPV=Net Present Value

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

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

## *Energy Efficiency Performance*

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

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

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

## *Demand Response Performance*

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

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

**Table 6.3 2022 demand response program capacity**

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

* Values may not add to 100% due to rounding

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

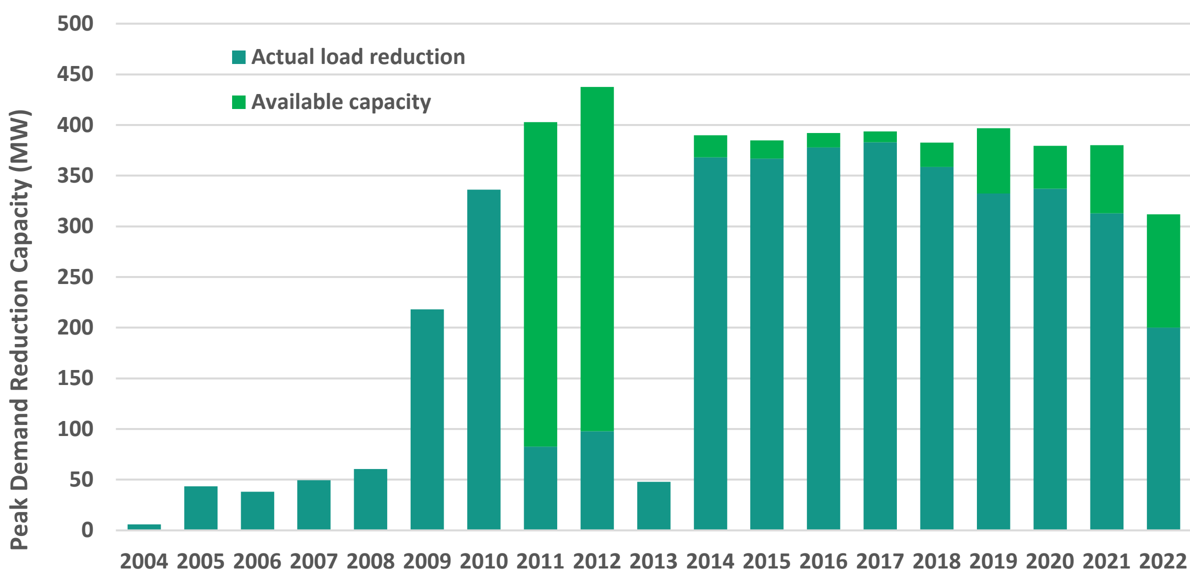



**Figure 6.2 Historic annual demand response program performance**

## Demand Response Resource Potential

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

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

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

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

## T&D Deferral Benefits

### *Energy Efficiency*

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

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

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

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

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

## Distribution System Planning

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

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

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

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

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

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

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

# 7. TRANSMISSION PLANNING

## Past and Present Transmission

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

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

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

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

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

## Transmission Planning Process

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

### *Local Transmission Planning*

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

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

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

### *Regional Transmission Planning*

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

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

## Existing Transmission System

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

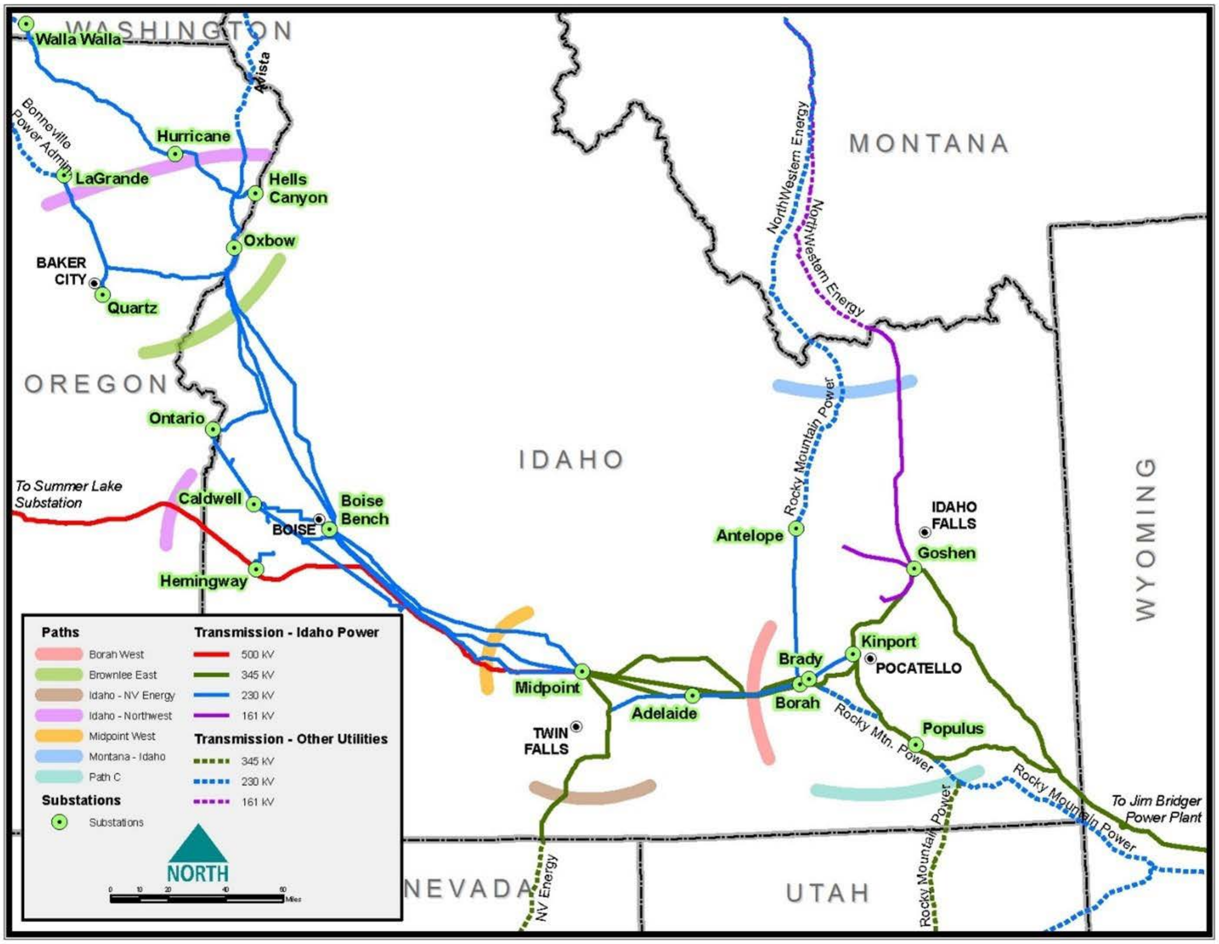



**Figure 7.1 Idaho Power transmission system map**

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

### Idaho to Northwest Path

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

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

### Brownlee East Path

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

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

### Idaho–Montana Path

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

### Borah West Path

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

### Midpoint West Path

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

### Idaho–Nevada Path

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

### Idaho–Wyoming Path

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

### Idaho–Utah Path

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

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

**Table 7.1 Transmission import capacity**

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

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

## Existing Transmission Capacity for Firm Market Imports

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

### *Idaho to Northwest and Idaho-Montana Path Firm Market Imports*

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

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

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

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

### Idaho to Northwest Path Utilization

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

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

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

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

### Idaho—Montana Path Utilization

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

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

### Idaho—Utah Path Utilization

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

### Existing Transmission Modeling in the 2023 IRP

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

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

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

### Capacity Benefit Margin Details

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

### Transmission Reliability Margin Details

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

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

## Boardman to Hemingway

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

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

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

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

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

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

### *B2H Value*

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

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

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

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

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

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

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

### *Project Participants*

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

**Table 7.5 B2H capacity allocation**

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

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

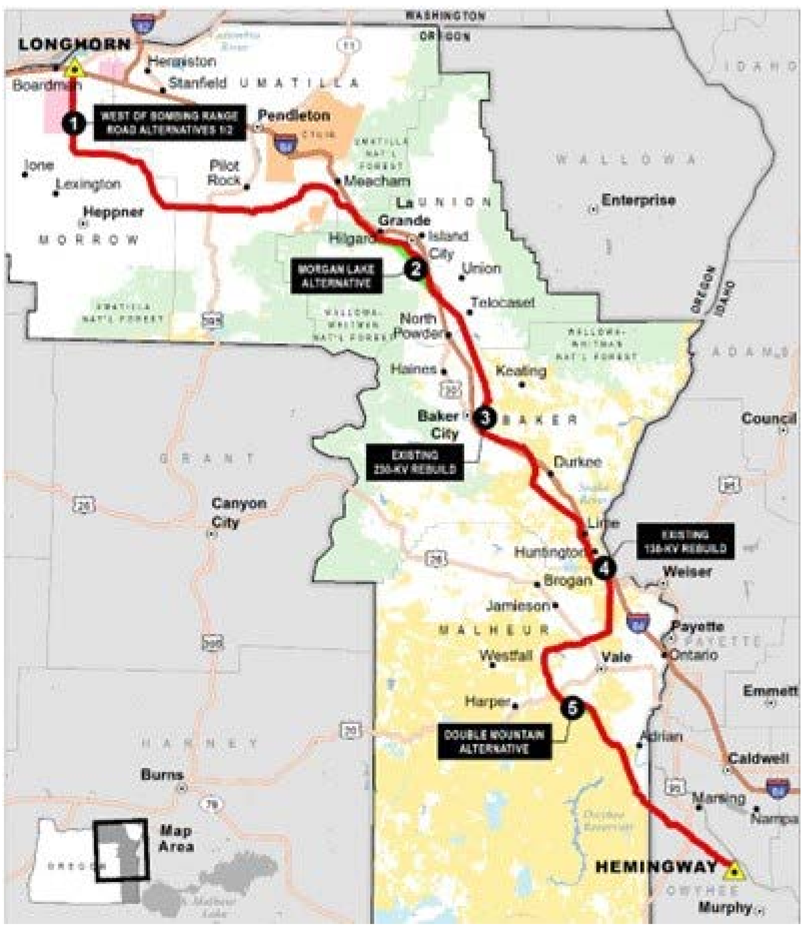



**Figure 7.2 B2H route submitted in 2017 Oregon Energy Facility Siting Council Application for Site Certificate**

## B2H Related Asset Exchange—Four Corners Capacity

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

**Table 7.6 List of transmission entities at Four Corners and Mona**

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

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

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

## Permitting Update

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

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

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

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

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

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

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

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

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

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

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

### Construction Update Next Steps

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

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

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

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

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

### B2H Modeling in the IRP

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

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

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

### *B2H Cost Treatment in the IRP*

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

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

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

## Gateway West

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

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

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

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


**Figure 7.3 Gateway West map**

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

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

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

### Gateway West—Segment 8 and Mayfield Substation

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

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

### Gateway West—Segment 9 and Cedar Hills Substation

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

### Gateway West—Segment 10

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

### Gateway West Cost Treatment and Modeling in the 2023 IRP

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


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

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

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

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

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

**Table 7.7 Gateway West phase modeling**

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

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

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

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

## Southwest Intertie Project-North

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

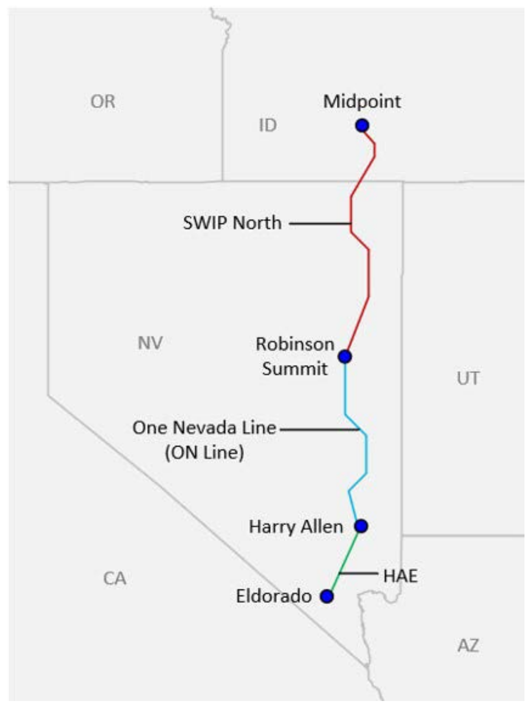
Building on the SWIP-N sensitivity analysis performed in the previous 2021 IRP cycle that showed potential cost savings with participation in the project, Idaho Power performed additional analysis on the project in this IRP. The California Independent System Operator (CAISO) has also expressed interest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

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

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

### Southwest Market Opportunity

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




SWIP-N Preliminary Route.

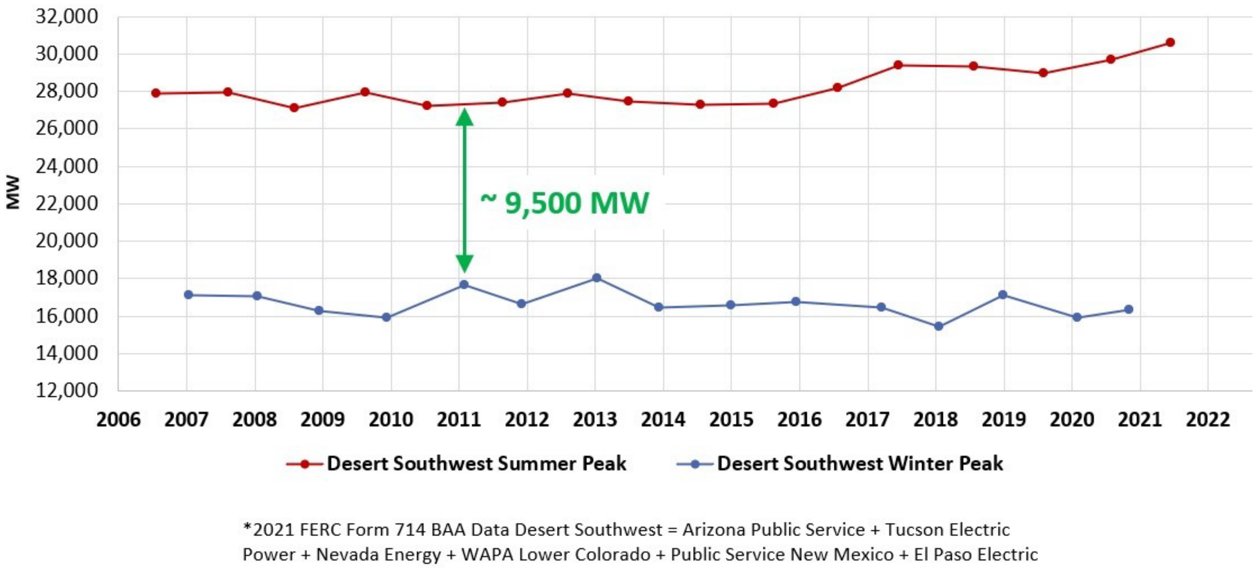



**Figure 7.4 Historical Desert Southwest Summer and Winter Seasonal Peaks**

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

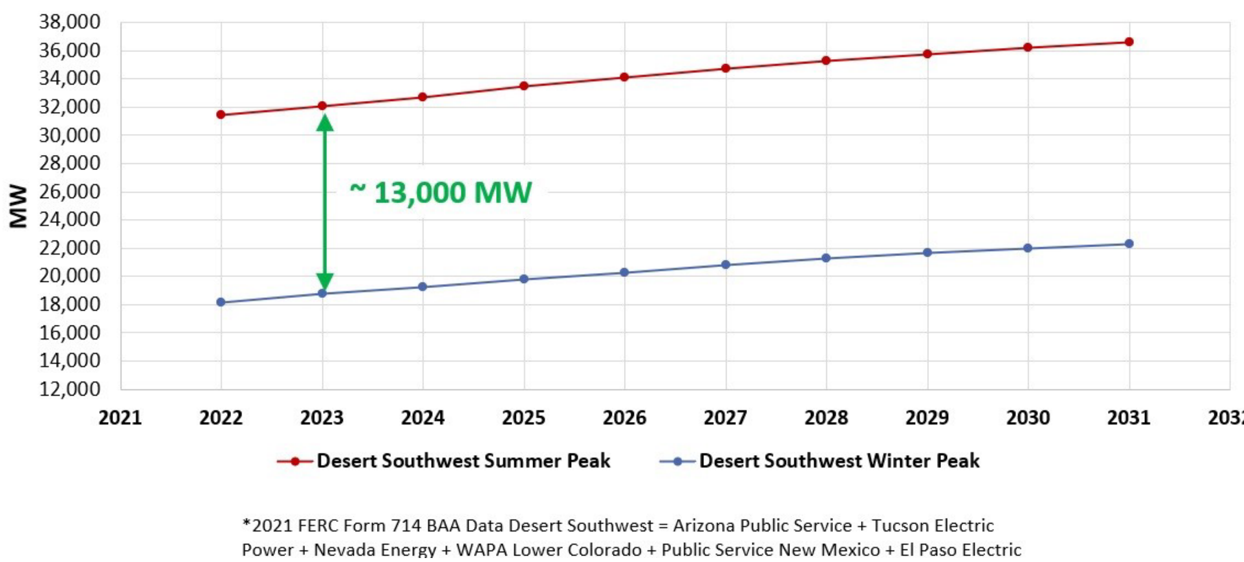



**Figure 7.5 Forecasted Desert Southwest Summer and Winter Seasonal Peaks**

## Federal Funding Opportunities for Transmission

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

## Transmission Assumptions in the IRP Portfolios

Transmission lines under construction at the Hemingway substation.

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

**Table 7.8 Transmission assumptions and requirements**

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

# 8. PLANNING PERIOD FORECASTS

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

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

Chobani plant near Twin Falls, Idaho.

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

## Load Forecast

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

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

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

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

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

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

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

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

### Weather Effects

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

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

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

### Economic Effects

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

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

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

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

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

### Average-Energy Load Forecast

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

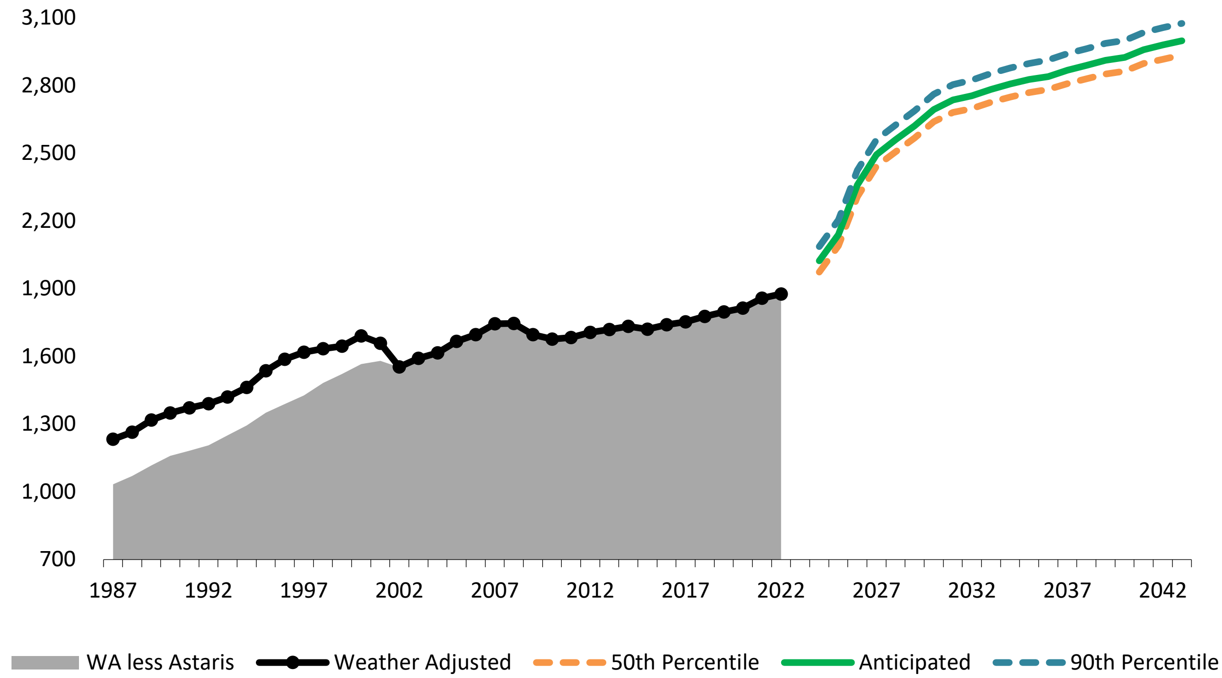



**Figure 8.1 Average monthly load-growth forecast (aMW)**

**Table 8.1 Load forecast—average monthly energy (aMW)**

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

## *Peak-Hour Load Forecast*

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

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

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

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

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

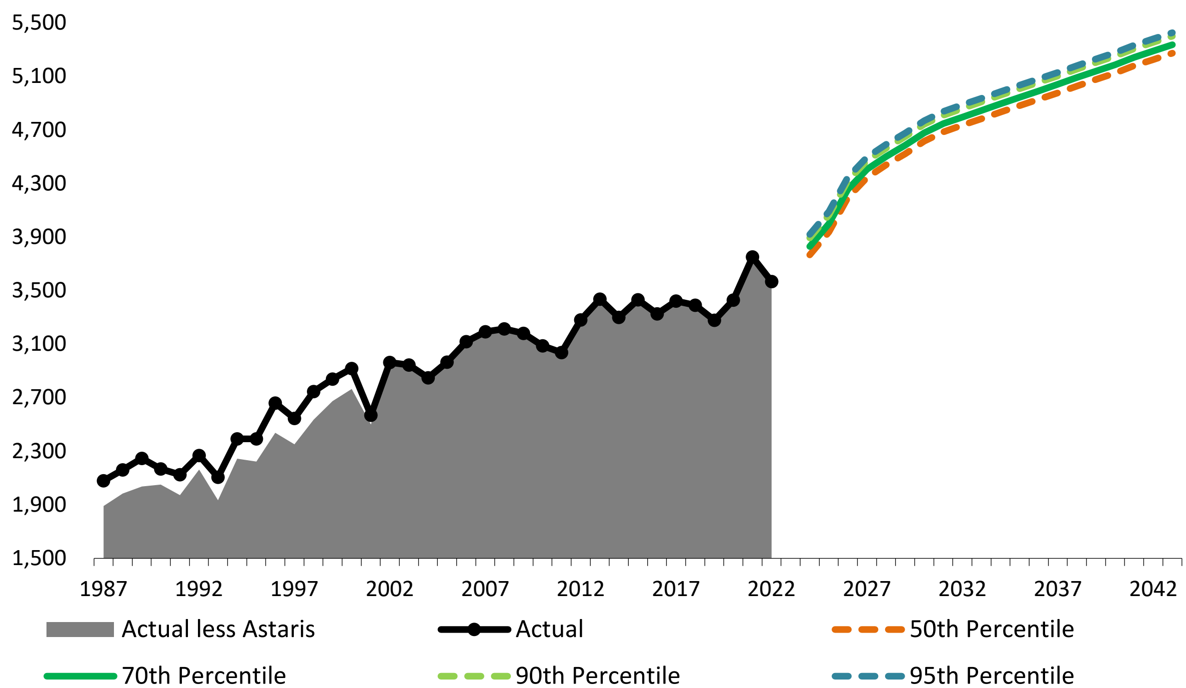



**Figure 8.2 Peak-hour load-growth forecast (MW)**

**Table 8.2 Load forecast—peak hour (MW)**

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

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

## *Additional Firm Load*

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

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

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

### Micron Technology

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

### Simplot Fertilizer

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

### INL

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

### Brisbie, LLC (Meta Platforms, Inc.)

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

## Generation Forecast for Existing Resources

### *Hydroelectric Resources*

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

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

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

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

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

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

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

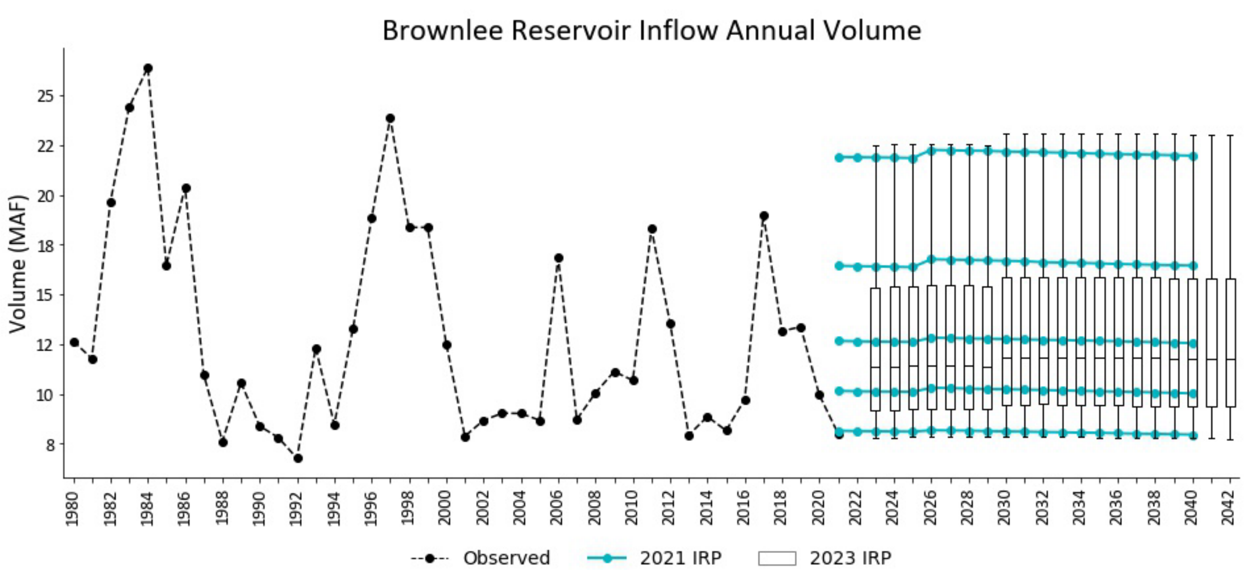


**Figure 8.3 Brownlee inflow volume historical and modeled percentiles**

### *Natural Gas Resources*

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

## Natural Gas Price Forecast

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

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

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

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

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

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

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

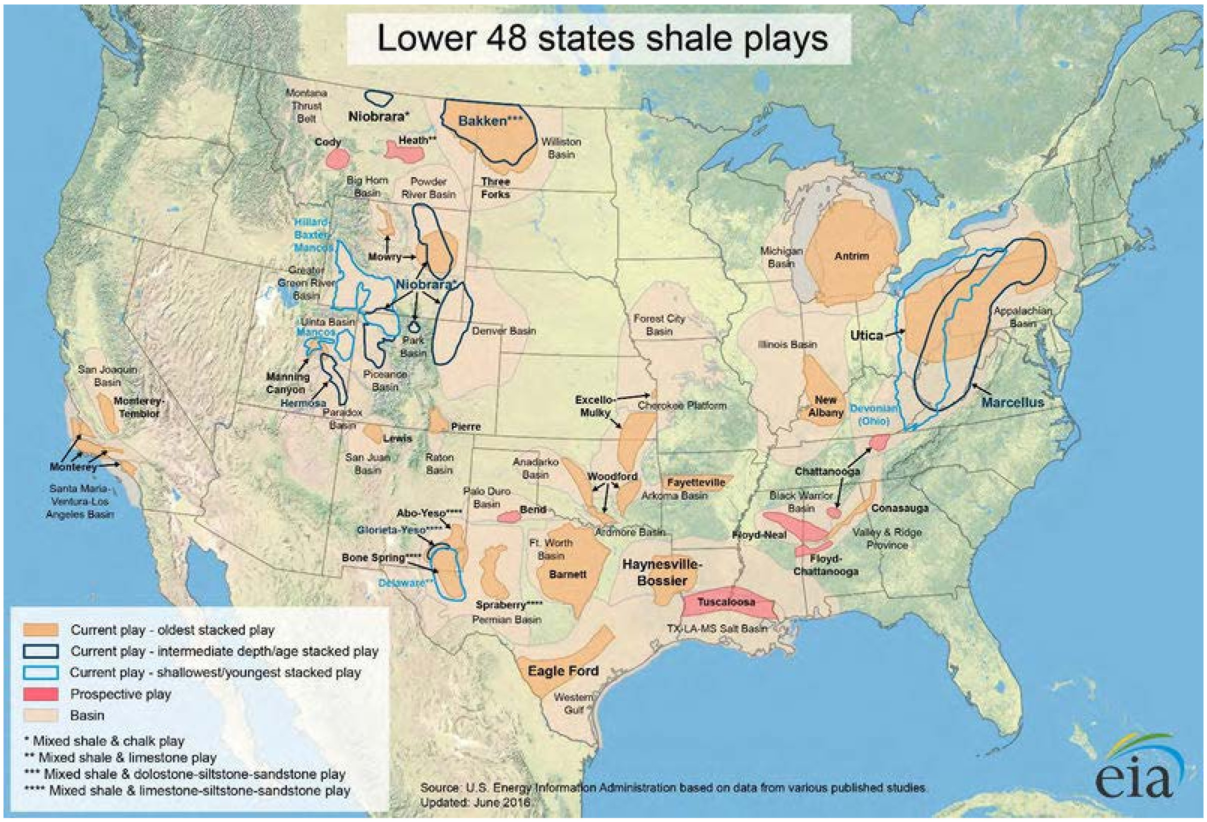



**Figure 8.4 North American major gas basins**

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

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

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

## Natural Gas Transport

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

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

## Natural Gas Storage Facilities

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

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

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

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

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

## Analysis of IRP Resources

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

### *Resource Costs—IRP Resources*

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

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

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

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

### *LCOC—IRP Resources*

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

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

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

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

### LCOE—IRP Resources

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

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

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

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

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

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

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

Note: columns may not perfectly add up due to rounding

## *Resource Attributes—IRP Resources*

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

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

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

**Table 8.5 Resource attributes**

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

The following resource attributes are considered in this analysis:

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

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

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

# 9. PORTFOLIOS

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

## Capacity Expansion Modeling

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

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

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

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

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

## Capacity Planning Reserve Margin

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

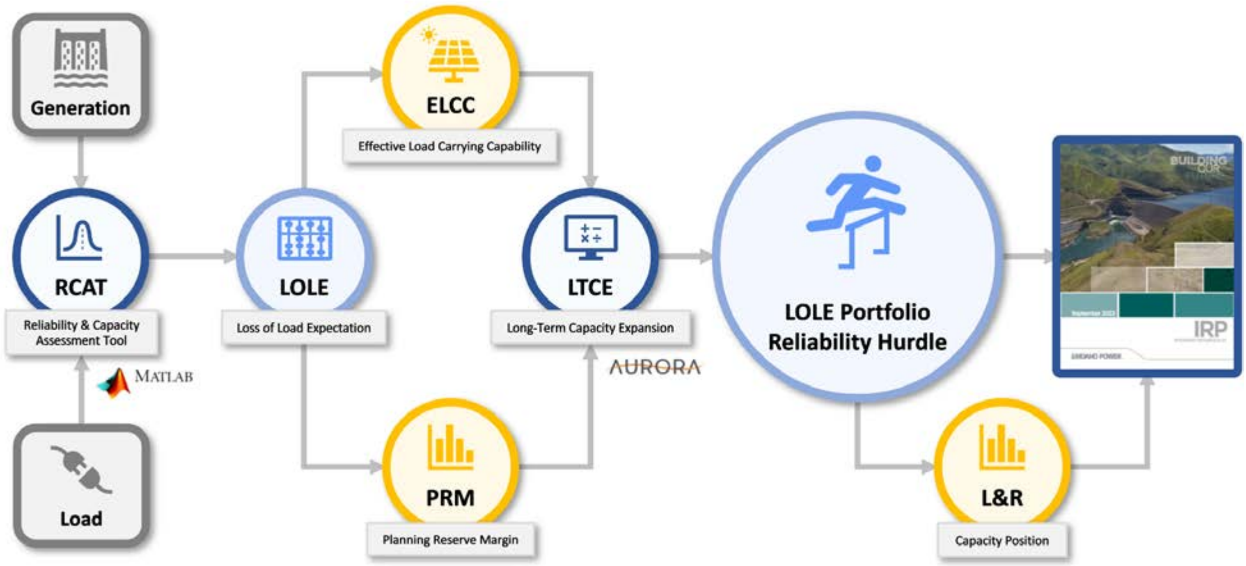



**Figure 9.1 Idaho Power's reliability flowchart**

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

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

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

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

## Regulation Reserves

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

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

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

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

Inputs to AURORA Model
Calculated Reserve Amounts by Percentage of Corresponding Load/Generation

## Portfolio Design Overview

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

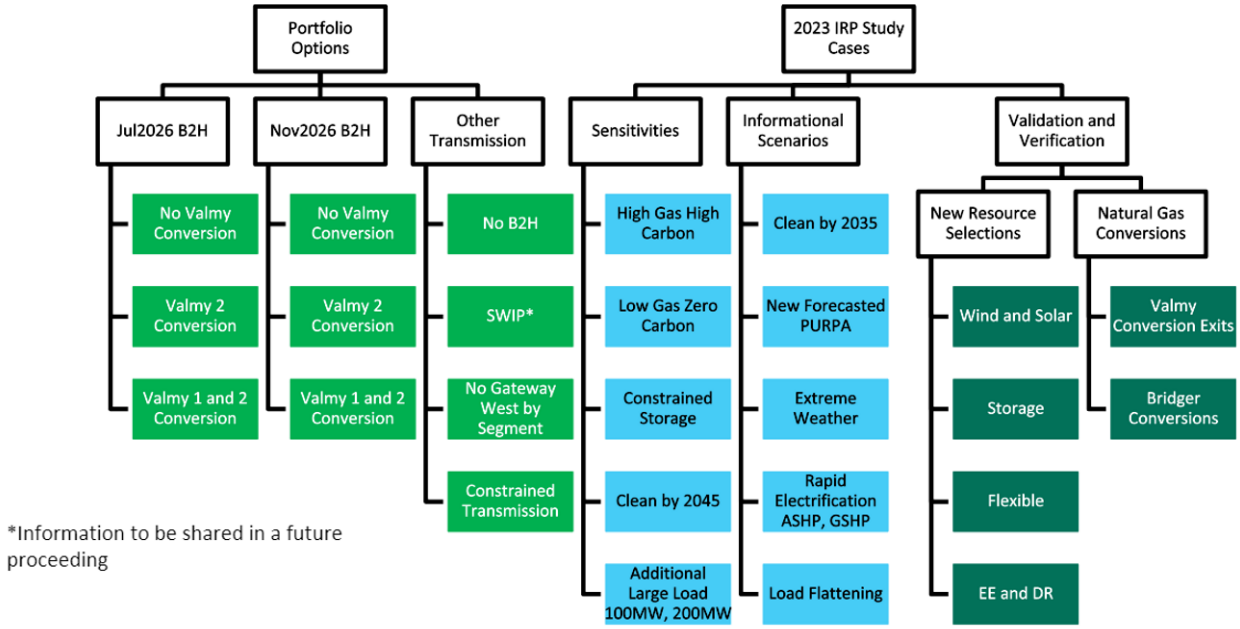



**Figure 9.2 Analysis diagram**

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

## *Portfolio Naming Conventions*

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

**Table 9.2. Planning conditions table**

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

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

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

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

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

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

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

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

## *Future Scenarios—Purpose: Risk Evaluation*

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

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

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

### High Gas High Carbon

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

**Table 9.3 High Gas High Carbon table**

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

### Low Gas Zero Carbon

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

**Table 9.4 Low Gas Zero Carbon table**

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

### Constrained Storage

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

### 100% Clean by 2035

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

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

### 100% Clean by 2045

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

### Additional Large Load

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

### New Forecasted PURPA

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

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

### Extreme Weather

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

### Rapid Electrification

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

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

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

### Load Flattening

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

## *Model Validation and Verification*

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

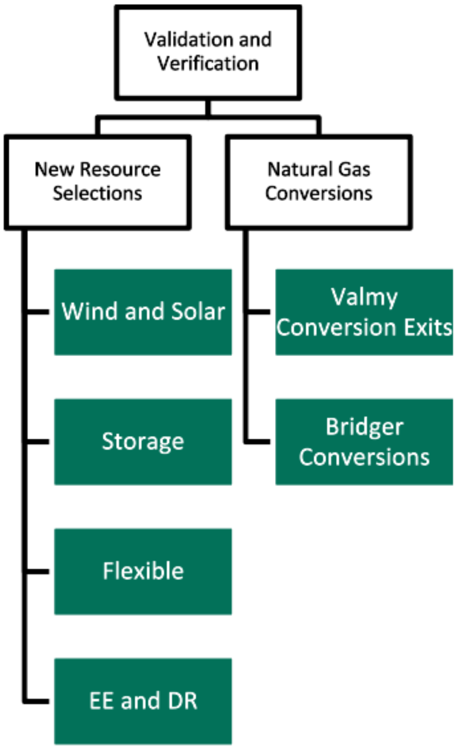



**Figure 9.3 Model validation and verification tests**

### Bridger

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

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

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

### Valmy

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

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

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

### New Resource Selections

#### Wind

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

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

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

#### Battery Storage

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

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

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

#### Nuclear

**Background**—Nuclear was not selected in the Preferred Portfolio.

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

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

#### Additional EE Bundles

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

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

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

#### Demand Response

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

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

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

### *B2H Timing*

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

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

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

## Natural Gas Price Variation Portfolios

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

## Carbon Price Variation Portfolios

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

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

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

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

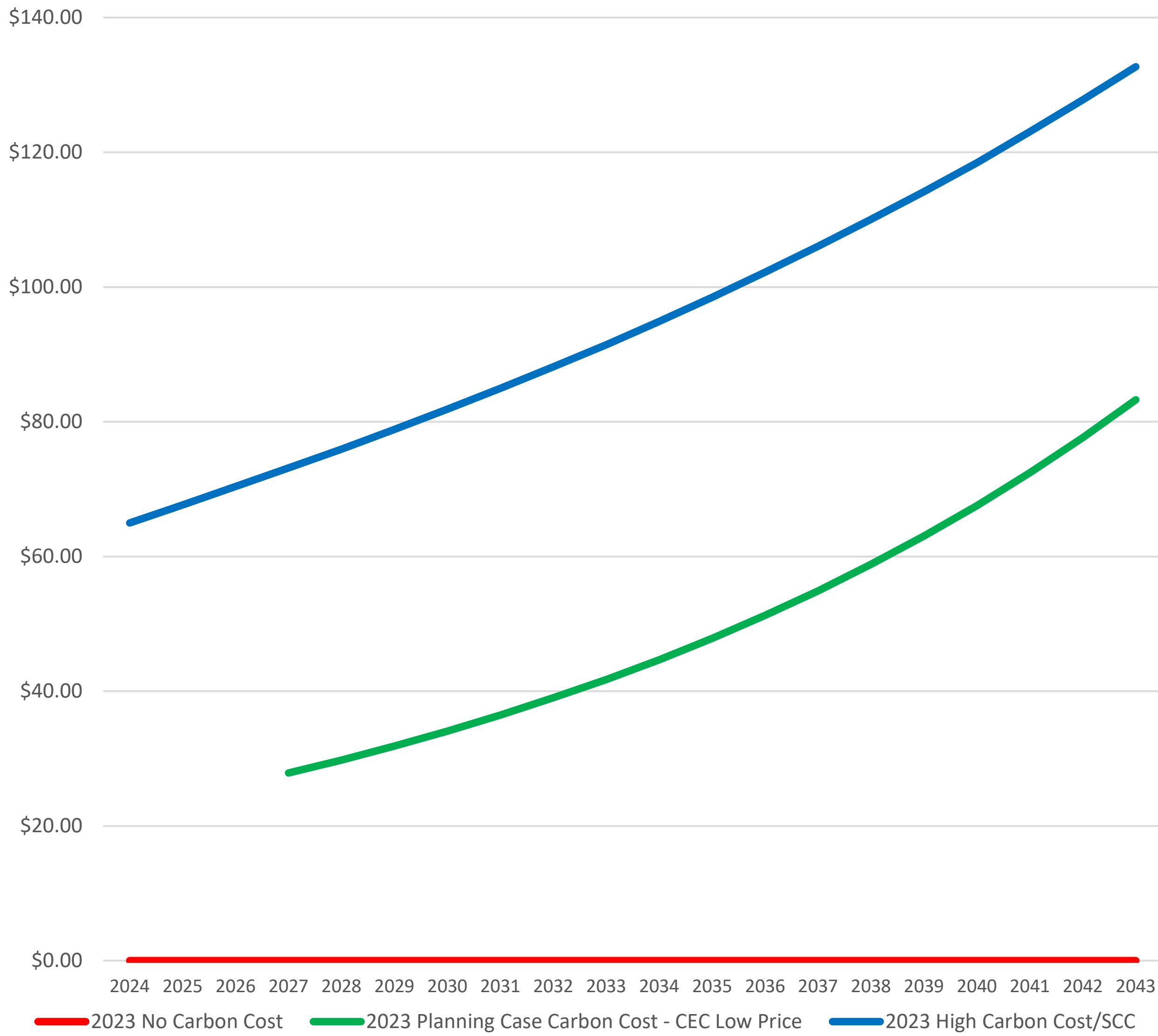



**Figure 9.4 Carbon price forecast**

# 10. MODELING ANALYSIS

## Portfolio Cost Analysis and Results

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

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

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

**Table 10.1 Financial assumptions**

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

The purpose of the AURORA hourly simulations is to compare how portfolios perform throughout the 20-year timeframe of the IRP. These simulations include the costs associated with adding generation resources (both supply-side and demand-side) and optimally dispatching the resources to meet the constraints within the model. The results from the main case simulations, including different transmission and Valmy conversion assumptions, are shown in Table 10.2. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

**Table 10.2 2023 IRP main cases**

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

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

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

**Table 10.3 2023 IRP sensitivities**

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

The validation and verification tests are listed in Table 10.4. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the Near-Term Action Plan window, to ensure the model was optimizing correctly and to test assumptions. More details on the setup and expected outcome of each test are provided in Chapter 9.

**Table 10.4 2023 IRP validation and verification tests**

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

## *Portfolio Emission Results*

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

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

The information presented in figures 1.4 and 3.2 demonstrate that Idaho Power's $CO_2$ emissions can be expected to trend downward over time. Idaho Power will continue to evaluate resource needs and alternatives that balance cost and risk, including the relative potential $CO_2$ emissions.

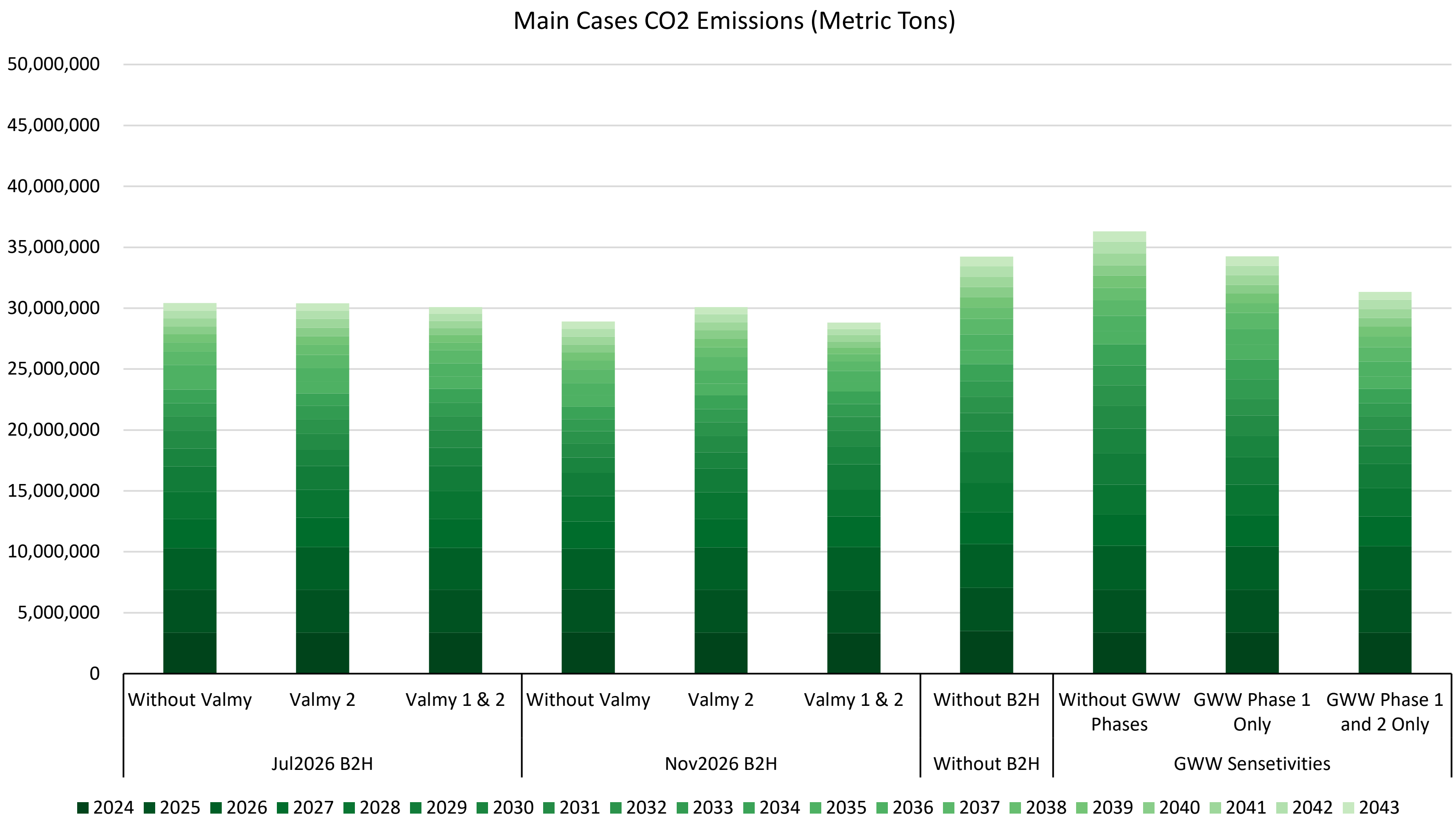



**Figure 10.1 Estimated portfolio emissions from 2021–2040**

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

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

## Qualitative Risk Analysis

### *Major Qualitative Risks*

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

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

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

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

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

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

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

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

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

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

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

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

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

**Table 10.5 Qualitative risk comparison**

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

## Stochastic Risk Analysis

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

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

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

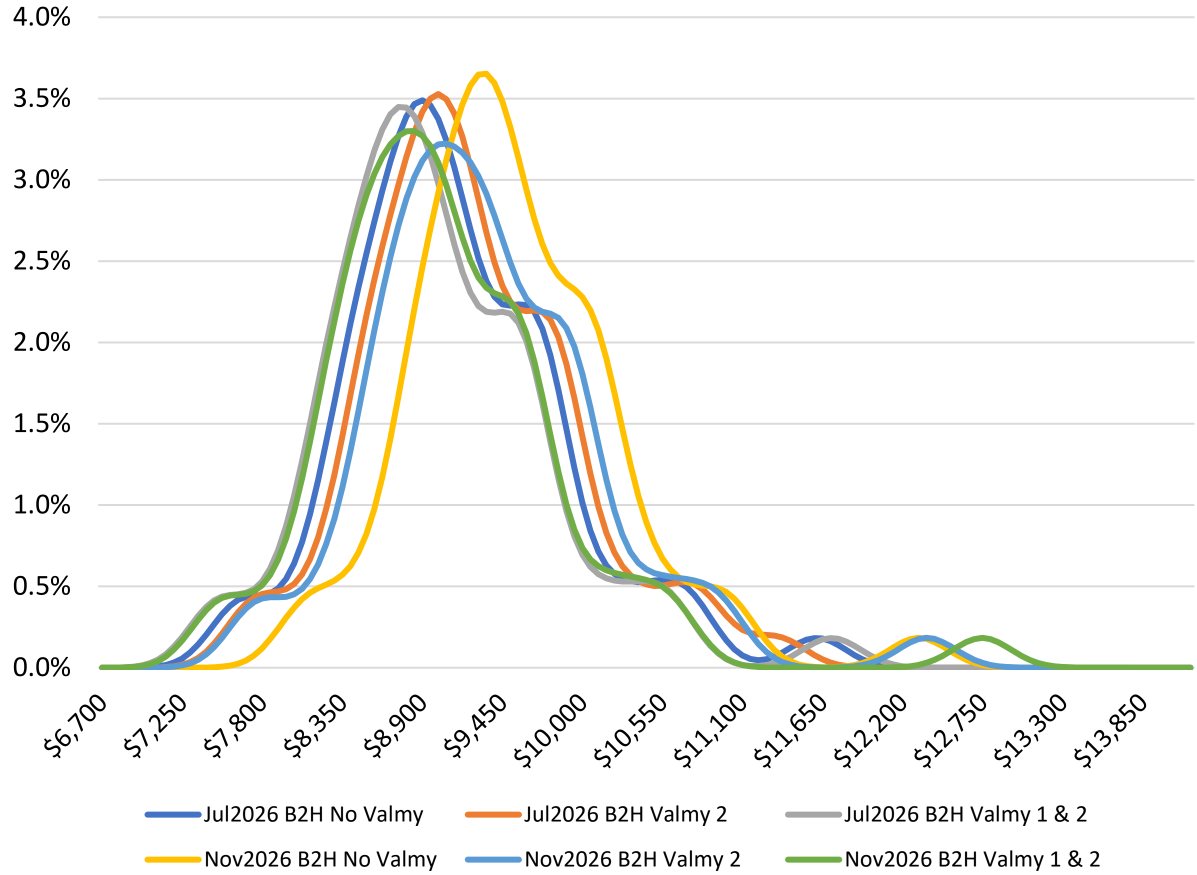



**Figure 10.2 NPV stochastic probability kernel—Preferred Portfolio contenders (likelihood by NPV [$ x 1,000])**

## Loss of Load Expectation Based Reliability Evaluation of Portfolios

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

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

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

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

## *Annual Capacity Positions of the Preferred Portfolio*

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

**Table 10.6 Preferred Portfolio annual capacity positions (MW)**

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

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

# 11. PREFERRED PORTFOLIO AND NEAR-TERM ACTION PLAN

## Preferred Portfolio

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

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

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

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

The Preferred Portfolio (Valmy 1 & 2) follows.

**Table 11.1Preferred Portfolio resource selections**

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

The following items are included in Table 11.1:

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

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

## Preferred Portfolio Compared to Varying Future Scenarios

### High Gas High Carbon

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

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

**Table 11.2 Preferred Portfolio—High Gas High Carbon comparison table**

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

*Geothermal Nuclear Biomass

### Low Gas Zero Carbon

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

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

**Table 11.3 Preferred Portfolio—Low Gas Zero Carbon comparison table**

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

*Geothermal Nuclear Biomass

### Constrained Storage

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

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

**Table 11.4 Preferred Portfolio—Constrained Storage comparison table**

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

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

*Geothermal Nuclear Biomass

### 100% Clean by 2035

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

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

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

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

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

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### 100% Clean by 2045

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

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

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

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

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

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### Additional Large Load

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

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

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

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

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

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

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### New Forecasted PURPA

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

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

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

**Table 11.9 Preferred Portfolio—New Forecasted PURPA comparison table**

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

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### Extreme Weather

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

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

**Table 11.10 Preferred Portfolio – Extreme Weather comparison table**

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

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### Rapid Electrification

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

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

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

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

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

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

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

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

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### Load Flattening

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

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

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

**Table 11.13 Preferred Portfolio—Load Flattening comparison table**

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

*Geothermal Nuclear Biomass

## Near-Term Action Plan (2024–2028)

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

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

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

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

### *2023 IRP Decisions for Acknowledgment*

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

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

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

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

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

## Resource Procurement

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

### *Annual Capacity Positions Replace Traditional Load and Resource Balance*

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

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

**Table 11.15 Pre and post Preferred Portfolio annual capacity positions**

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

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

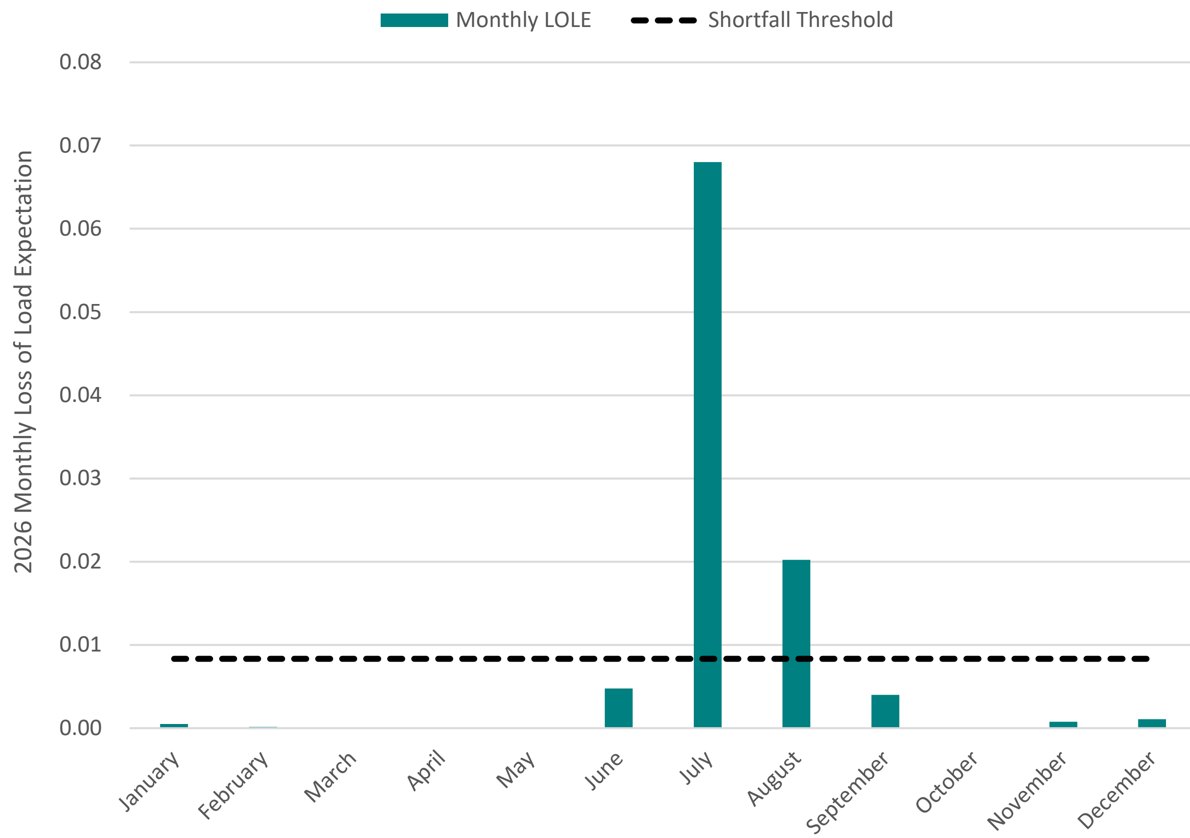


**Figure 11.1 First month of capacity shortfall**

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

## 2025 IRP Filing Schedule

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

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

## Conclusion

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

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

Idaho Power linemen install upgrades.

# BUILDING OUR FUTURE

September 2023

# IRP

## INTEGRATED RESOURCE PLAN

APPENDIX A: **SALES & LOAD FORECAST**

IDAHO POWER®

## SAFE HARBOR STATEMENT

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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2023 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 2024 through 2043.

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 1.6% 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 also projected to grow faster than the state of Idaho, at an annual rate of 2.2% 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 anticipated forecast scenario shows Idaho Power's system load increasing to 2,999 average megawatts (aMW) by 2043 from 2,024 aMW in 2024, representing an average yearly growth rate of 2.1% over the 20-year planning period (2024–2043). 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 5,337 megawatts (MW) in 2043 from the all-time system peak of 3,751 MW that occurred on Wednesday, June 30, 2021, at 7 p.m. Idaho Power's system peak increases at an average growth rate of 1.8% per year over the 20-year planning period (2024–2043) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2022 level of 616,857 customers to over 855,000 customers by year-end 2043.

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 2022 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 impact of their energy reduction or addition in the long-term sales and load forecast. Further discussion of these assumptions is presented in each respective 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. Additionally, 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.

# 2023 IRP SALES AND LOAD FORECAST

## Average Load

The economic and demographic variables driving the 2023 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 was attributable to both work-from-home edicts as well as continued strong in-migration trends. In the second half of 2022 and into 2023, migration trends have slowed relative to previous years. However, net migration growth into the service area remains positive and more consistent with long-term trends. Negative energy use was initially exhibited by the commercial and industrial classes but has since stabilized and, overall, rebounded quickly. Irrigation sales were mostly unaffected by the pandemic and continue to follow the expected growth trend. Overall, it is assumed economic conditions will return to long-term fundamentals during the 2023 IRP forecast term. Additional significant factors and considerations that influenced the outcome of the 2023 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 load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Probabilistic variations of weather are also analyzed.
- The economic forecast used for the 2023 IRP reflects a softened expansionary economy in Idaho over the near term and reversion to the long-term trend of the service area economy. While Idaho had the highest residential population growth rate of any state in the nation for the 5 years ending 2020, customer growth and residential permit issuances have come down from those highs in 2022. However, net migration and business investment continues to result in positive economic activity.
- 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 (UPC) over much of the forecast period.

- New industrial and Energy Service Agreement (ESA) customer requests are inherently uncertain regarding location and capacity needs. 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 2023 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2021 IRP preferred portfolio. Retail electricity prices throughout the planning period can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

## Peak-Hour Demands

Average loads, as discussed in the preceding section, are an integral component to the load forecast, as is the impact of the peak-hour demands on the system. Like the sales forecast discussed in the preceding section, the peak models incorporate several peak forecast scenarios based on historical probabilities of peak day temperatures at the 50$^{th}$, 70$^{th}$, 90$^{th}$, and 95$^{th}$-percentiles of occurrence for each month of the year. The peak-hour demands (peaks) are forecasted separately using regressions that are expressed as a function of the sales (average load) forecast as well as the impact of peak-day temperatures. More discussion is provided in the forthcoming sections.

The peak forecast results and comparisons with previous forecasts differ for many reasons, including the following:

- The all-time system summer peak demand was 3,751 MW, recorded 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 Friday, July 2, 2013, at 5 p.m. Idaho Power's winter peak-hour load record is 2,604 MW, recorded December 22, 2022, at 9 a.m. The previous winter peak-hour load record was 2,527 MW, realized December 10, 2009, at 8 a.m., and matched January 6, 2017, at 9 a.m.
- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50$^{th}$, 70$^{th}$, 90$^{th}$, and 95$^{th}$-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1993 to 2022 period (the most recent 30 years).

- The 2023 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

# OVERVIEW OF THE FORECAST AND SCENARIOS

The sales and load forecast is constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and ESA customers. 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 $50^{th}$-percentile average load forecast assumes average temperatures and precipitation (i.e., there is a 50% chance loads will be higher or lower than the anticipated load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation). However, the 30-year climatology has been increasing over the past several decades, implying a cold bias in the calculation. Since actual loads can vary significantly depending on weather conditions, alternative scenarios were developed to address load variability due to variable weather—the $70^{th}$- and $90^{th}$-percentile load forecasts. The $70^{th}$-percentile weather was utilized in the anticipated case to adjust for any systemic historic changes.

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 degree days (CDD) and growing degree days (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 1993 to 2022 (the most recent 30 years) was 1,020 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 90th-percentile HDD is 1,126 and would be exceeded in 1 out of 10 years. As an example, for a single month, the near 100th-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 multiple 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 2023 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 |
| Anticipated Case | 70% | 3 in 10 years | HDD, CDD, GDD, precipitation |
| 50th Percentile | 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 |
| 70th Percentile | 70% | 3 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 | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 90th Percentile | 2,087 | 2,627 | 2,854 | 3,076 | 2.1% |
| Anticipated Case | 2,024 | 2,561 | 2,784 | 2,999 | 2.1% |
| 50th Percentile | 1,974 | 2,507 | 2,727 | 2,936 | 2.1% |

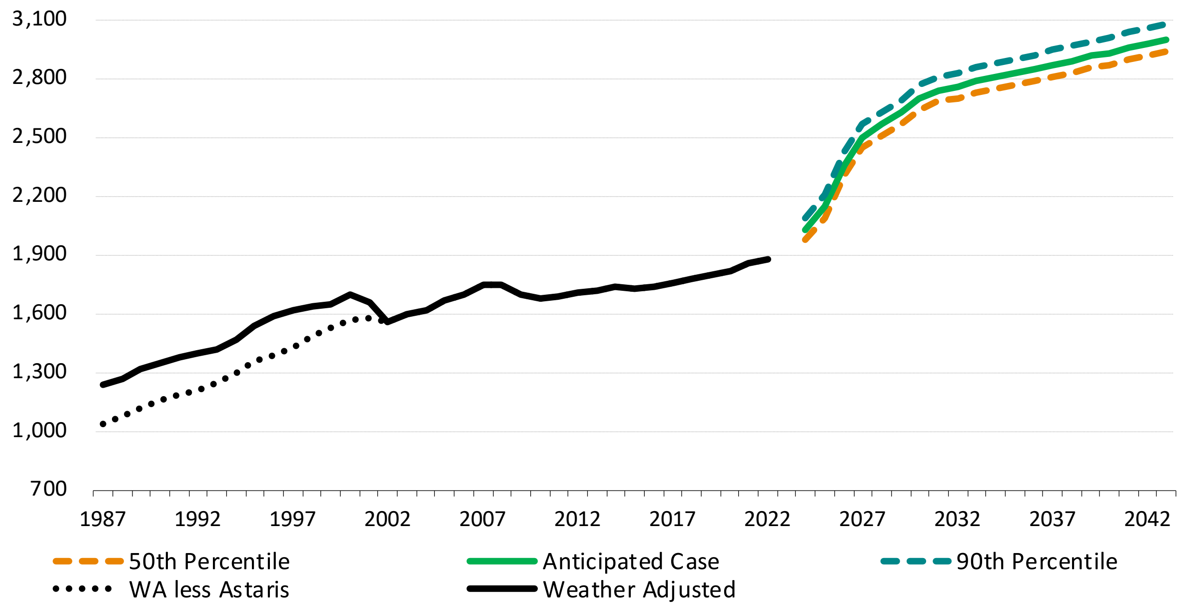



**Figure 1. Forecast system load (aMW)**[1]

## *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 2024 to 2043 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 (1998–2022).

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 (1998–2022).

[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 energy service agreement between Astaris and Idaho Power was terminated.

From the above methodology, two views of probable outcomes form the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed 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 ESA customers (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 2.1% per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 1.9% per year throughout the forecast period. The high scenario projects a load growth of 2.4% 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 | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| Low | 1,950 | 2,455 | 2,630 | 2,769 | 1.9% |
| Anticipated | 2,024 | 2,561 | 2,784 | 2,999 | 2.1% |
| High | 2,066 | 2,664 | 2,930 | 3,224 | 2.4% |

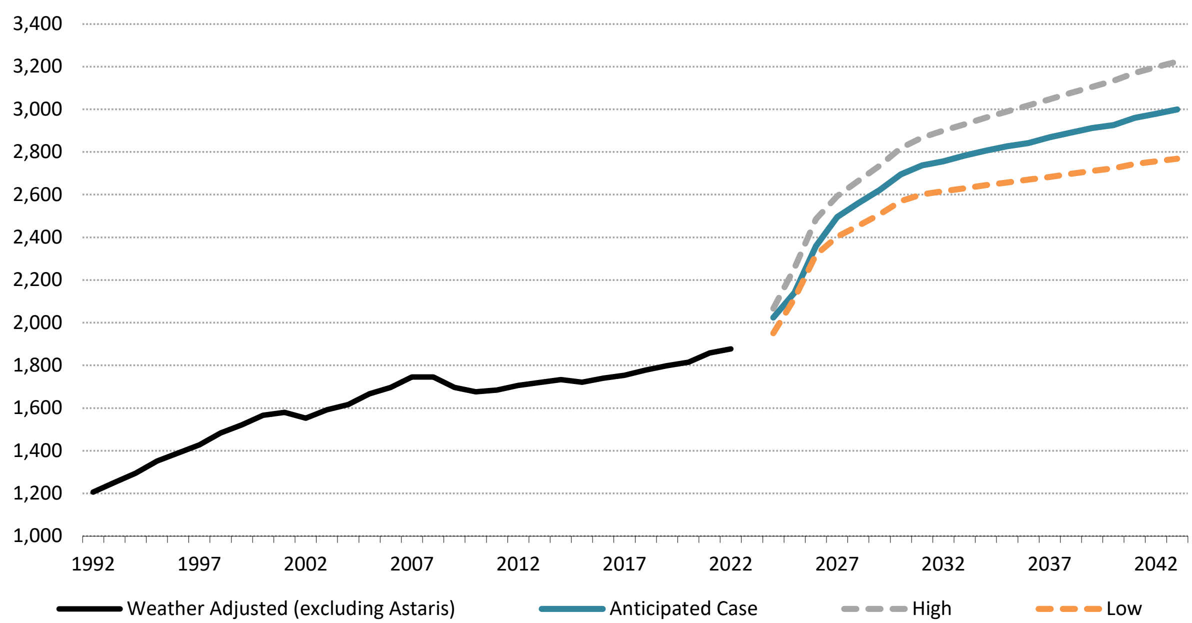



**Figure 2. Forecast system load (aMW)**

# COMPANY SYSTEM LOAD

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

The 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 2.1% per year from 2024 to 2043. Company system load projections are reported in Table 2 and shown in Figure 1.

In the 70th-percentile (anticipated) forecast, the company system load is expected to increase from 2,024 aMW in 2024 to 2,999 aMW in 2043, an average annual growth rate of 2.1%. In the weather sensitive scenarios, the 50th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,974 aMW in 2024 to 2,936 aMW by 2043 and increase from 2,087 aMW in 2024 to 3,076 aMW, respectively. All scenarios have an average growth rate of 2.1% per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,950 aMW in 2024 to 2,769 aMW in 2043, an average annual growth rate of 1.9% and in the high case from 2,066 aMW to 3,224 aMW, an average annual growth rate of 2.4% (Table 4).

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 22% higher in 2043, gaining 1.2 million megawatt hours (MWh) over 2024. Industrial sales are expected to be 28% higher, or 0.8 million MWh, followed by commercial (17% higher, or 0.7 million additional MWh) and irrigation (12% higher in 2043 than 2024). Additional firm sales are expected to more than quadruple by 2043, gaining 5 million MWh over 2024.

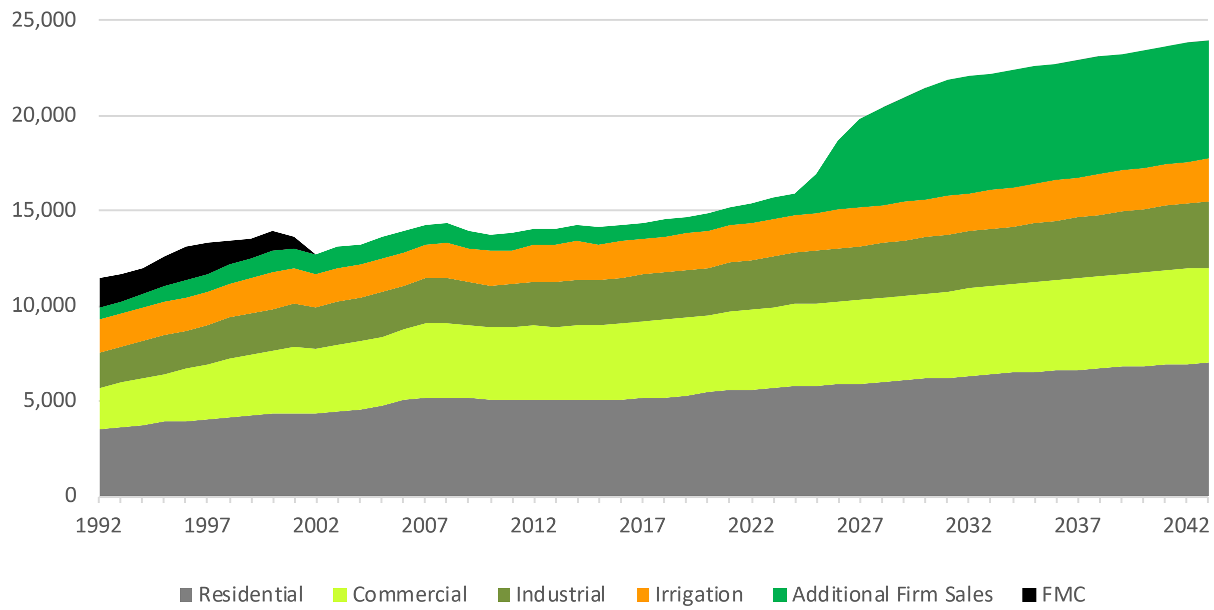



**Figure 3. Composition of system company electricity sales (thousands of MWh)**

## Additional Scenarios Developed

In addition to the anticipated sales forecast, differing weather probability cases, and high and low economic cases, alternative sales and load cases were developed for analysis within the 2023 IRP. These scenarios included load flattening, high penetration future of building and transportation electrification, and the addition of approximately 100 MW or 200 MW of capacity requirements to the load forecast due to high growth within the commercial and industrial classes. These additional scenarios are discussed in the following.

### *Load Flattening*

A scenario was generated in which the peak hours of the residential class were reduced, and the load shifted from the peak to the lowest load times of the day to fill in the load valleys. The objective of the load flattening scenario is not associated with a particular technology or policy, but rather is an exercise to test the resource portfolios.

The peak and valley hours for both summer and winter were identified by observing the hourly and seasonal trends of the residential class. A reduction of 10% was subtracted from each hour of the peaks and added to the valleys.

The summer peak is defined as the hours of 5 to 10 p.m. for the months of May through September. The summer demand was shifted to the hours of 3 to 8 a.m. the following day. The winter season is November through March and has both morning and evening peaks. These are defined as the hours of 7 to 10 a.m. and 6 to 10 p.m., respectively. The morning winter peak was moved to the subsequent valley of 1 to 4 p.m., and the evening peak was shifted to 1 to 4 a.m. the following day.

### Electrification Scenarios

Rapid electrification scenarios were generated for the IRP to inform Idaho Power of system load requirements should rapid and extensive electrification occur in Idaho Power's service area. Rapid electrification includes assumptions around both transportation and building electrification, which includes light-duty electric vehicles; residential heat pump water heaters; and residential air source (and ground source) heat pumps. These are discussed in detail below. It is important to note this does not represent an electrification path that is most likely, rather more on the far tails of electrification possibilities. The objective of the electrification scenario is not associated with a probable outcome but rather is an exercise to test the resource portfolios.

For the building electrification assumptions, current equipment saturations specified from Idaho Power's 2022 end-use study were identified and ramped up to an 80% saturation by the end of the planning period. These saturations are calibrated to Idaho Power's customer forecast to understand the number of units that would be on the system and thus the amount of energy required for the newly installed equipment. Those equipment saturations were cross-referenced to equipment usage specifications from Applied Energy Group's (AEG) LoadMAP models used in Idaho Power's 2022 energy efficiency potential study. Further, the newly installed units were assumed to be the most efficient equipment known today. The product of the saturations and resulting equipment annual usage was shaped to understand the hourly impacts over the planning period. Load shapes were taken from the Northwest Regional Technical Forum (RTF).

For transportation electrification, the electric vehicle adoption assumption was relaxed from the most probable outcome, as included in the base forecast used in the 2023 IRP, to reach a saturation level of 93% at the end of the planning period. The electric vehicle load shape was obtained from the RTF, which was modified from an Avista Utilities Electric Vehicle Supply Equipment (EVSE) study. The goal was to shift the primary amount of required load away from the typical summer peak hours into the late evening, as well as the late morning. During this process, it was also assumed workplace charging became more common.

In these scenarios, all electric vehicles and conversions of space/water heating from natural gas to electricity were load building. All electric resistance space/water heating and currently installed heat pumps and air conditioners were converted to more efficient heat pumps and reduced system load.

Idaho Power will continue to monitor electric vehicle registrations from the Idaho Department of Transportation, as well as update end-use studies every few years, to assess if a similar rapid and extensive electrification scenario is being entered into as modeled.

### *High Growth Scenarios*

Additional scenarios were run for high-growth futures in the Idaho Power service area. There have been numerous requests to Idaho Power for development of large commercial and industrial projects over the course of 2022 and 2023. These scenarios were developed to capture the potential of one of these projects moving forward and assess resource adequacy and cost. The first scenario represents a single or aggregate 100 MW added on to Idaho Power's system over the course of year 2026. The second scenario represents a single or aggregate 200 MW added on to Idaho Power's system, ramping up over the years 2026–2027.

# COMPANY SYSTEM PEAK

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as ESA customers (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 became standard in nearly all new residential homes and new commercial buildings.

In the 95$^{th}$-percentile forecast, the system summer peak load is expected to increase from 3,920 MW in 2024 to 5,427 MW in 2043. In the 90$^{th}$-percentile forecast, the system summer peak load is expected to increase from 3,894 MW in 2024 to 5,401 MW in 2043. In the 70$^{th}$-percentile forecast, or anticipated case, the system summer peak load is expected to increase from 3,830 MW in 2024 to 5,337 MW in 2043. Finally, in the 50$^{th}$-percentile forecast, the system summer peak load increases from 3,767 MW in 2024 to 5,274 MW in 2043. The 95$^{th}$- and 90$^{th}$-percentile forecasts represent an average summer peak growth rate of 1.7% per year over the planning period. The 70$^{th}$- and 50$^{th}$-percentile forecasts represent an average summer peak growth rate of 1.8% per year over the planning period (Table 5).

**Table 5. System summer peak load growth (MW)**

| Growth | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 95$^{th}$ Percentile | 3,920 | 4,592 | 4,937 | 5,427 | 1.7% |
| 90$^{th}$ Percentile | 3,894 | 4,565 | 4,911 | 5,401 | 1.7% |
| 70$^{th}$ Percentile | 3,830 | 4,501 | 4,847 | 5,337 | 1.8% |
| 50$^{th}$ Percentile | 3,767 | 4,439 | 4,784 | 5,274 | 1.8% |

The four 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.

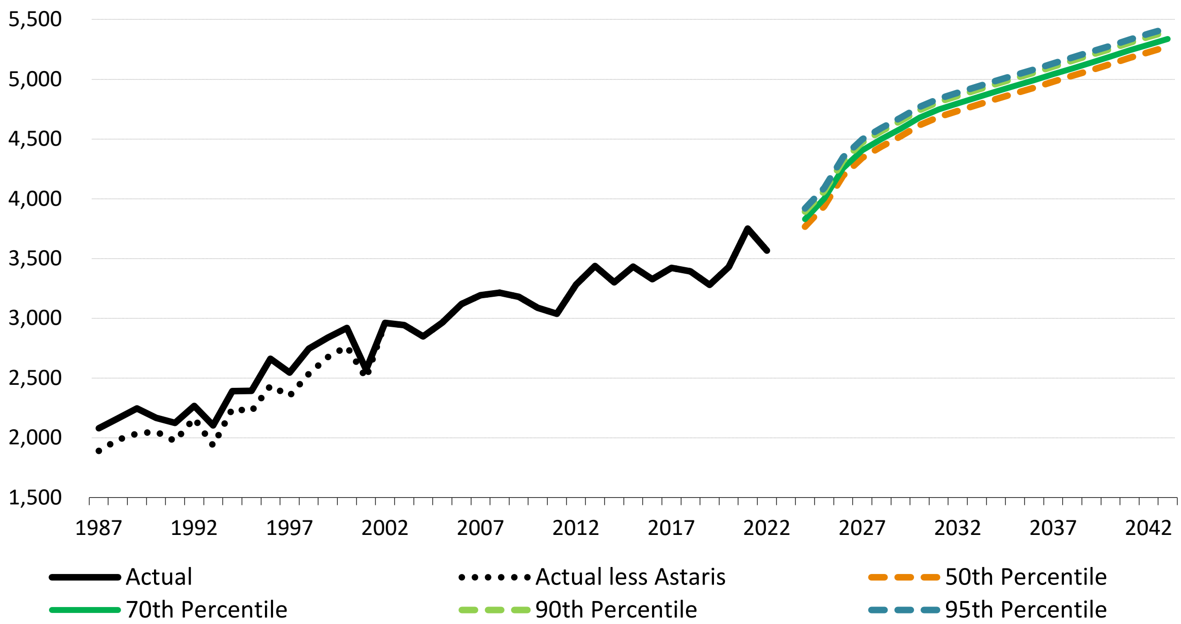



**Figure 4.** **Forecast system summer peak (MW)**

The all-time system winter peak demand was 2,604 MW, recorded Thursday, December 22, 2022, at 9 a.m. The previous all-time system winter peak demand was 2,527 MW, realized Thursday, December 10, 2009, at 8 a.m. and matched 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 95$^{th}$-percentile forecast, the system winter peak load is expected to increase from 2,750 MW in 2024 to 3,593 MW in 2043, an average growth rate of 1.4% per year over the planning period. In the 90$^{th}$-percentile forecast, the system winter peak load is expected to increase from 2,647 MW in 2024 to 3,557 MW in 2043, an average growth rate of 1.6% per year over the planning period. In the 70$^{th}$-percentile forecast, or anticipated case, the system winter peak is expected to increase from 2,567 MW in 2024 to 3,477 MW in 2043, an average growth rate of 1.6% per year over the planning period. In the 50$^{th}$-percentile forecast, the system winter peak load is expected to increase from 2,512 MW in 2024 to 3,422 MW in 2043, an average growth rate of 1.6% per year over the planning period. This data is represented in Table 6. The four scenarios of projected system winter peak load are illustrated in Figure 5.[2]

**Table 6. System winter peak load growth (MW)**

| Growth | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 95th Percentile | 2,750 | 3,269 | 3,441 | 3,593 | 1.4% |
| 90th Percentile | 2,647 | 3,165 | 3,379 | 3,557 | 1.6% |
| 70th Percentile | 2,567 | 3,085 | 3,299 | 3,477 | 1.6% |
| 50th Percentile | 2,512 | 3,029 | 3,243 | 3,422 | 1.6% |

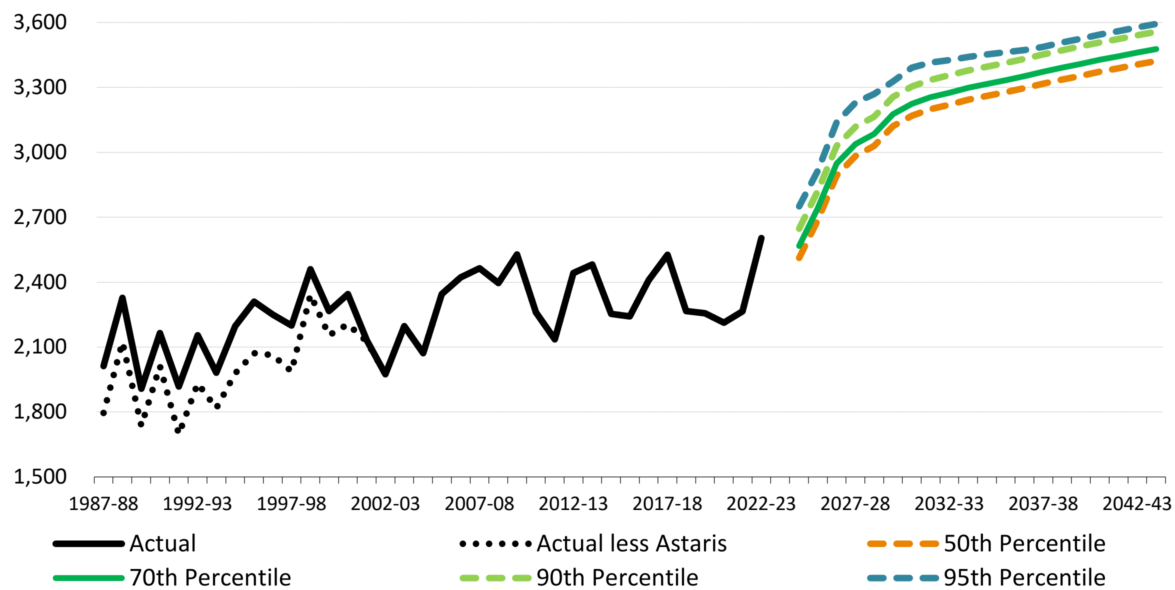



**Figure 5. Forecast system winter peak (MW)**

The historic relationship of summer and winter peaks is depicted in Figure 6. The growth in the summer peak over the past several decades in Idaho Power's service territory, as evidenced by

[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 1993 to 2022 period (the most recent 30 years).

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.

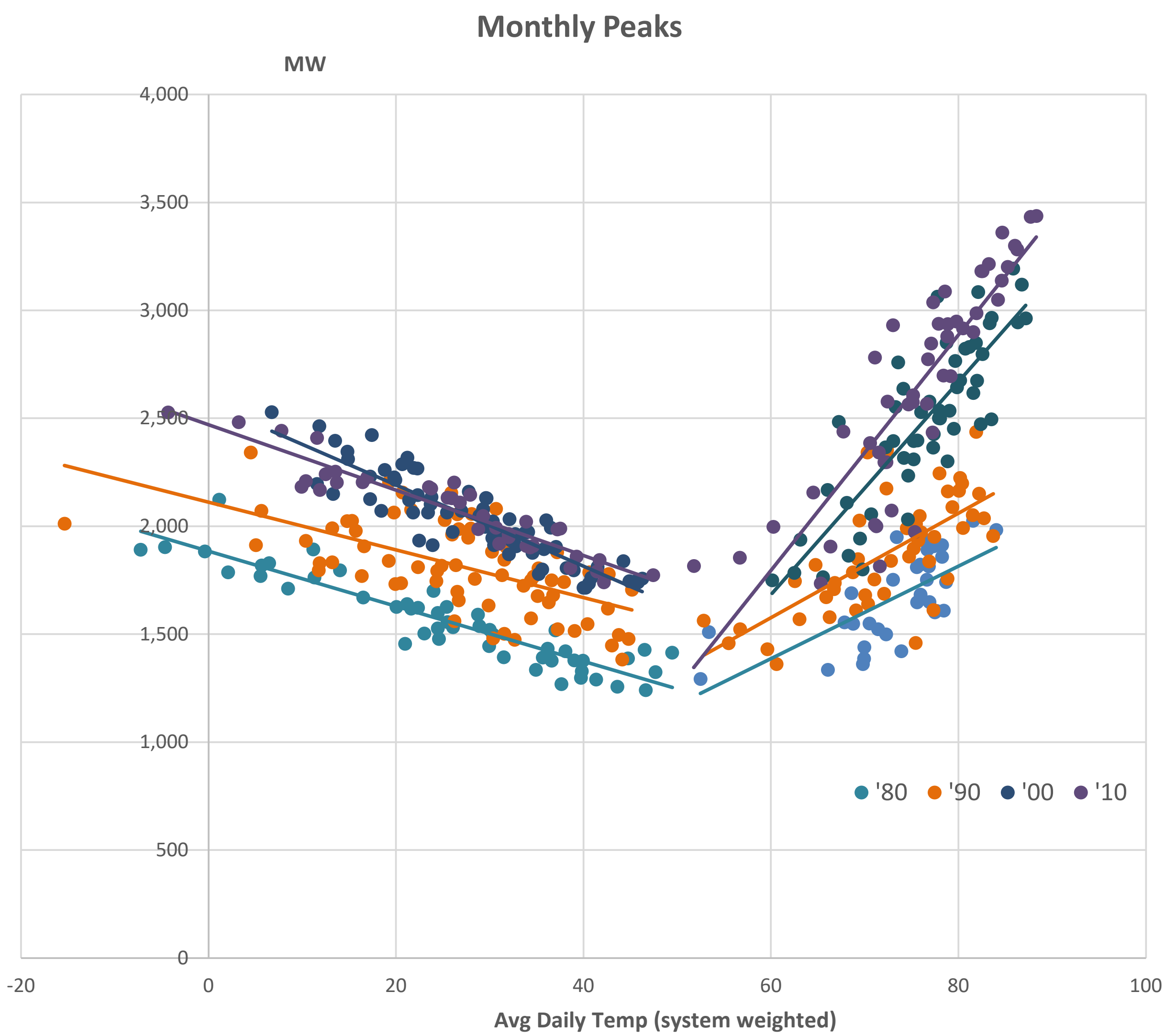



**Figure 6. Idaho Power monthly peaks (MW)**

Note the 2023 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.

## 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 over 20 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, and in some months, precipitation. The contribution to the system peak of the company's ESA 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 1993 to 2022 period (the most recent 30 years). In addition, the peak model develops peak scenarios based on historical probabilities of peak day temperatures at the $50^{th}$, $70^{th}$, $90^{th}$, and $95^{th}$ percentiles of occurrence for each month of the year.

Note the summertime (June through September) 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 2043, the end of the forecast period. 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 70th-percentile (anticipated) residential load is forecast to increase from 678 aMW in 2024 to 830 aMW in 2043, an average annual compound growth rate of 1.1%. In the 50th-percentile scenario, the residential load is forecast to increase from 655 aMW in 2024 to 799 aMW in 2043 at an average annual compound growth rate of 1.1%, matching the anticipated residential growth rate. The 90th-percentile residential load is forecast to increase from 707 aMW in 2024 to 870 aMW in 2043, also at an average annual compound growth rate of 1.1%. The residential load forecasts are reported in Table 7 and shown in Figure 7.

**Table 7. Residential load growth (aMW)**

| Growth | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 90th Percentile | 707 | 740 | 793 | 870 | 1.1% |
| Anticipated Case | 678 | 708 | 758 | 830 | 1.1% |
| 50th Percentile | 655 | 683 | 731 | 799 | 1.1% |

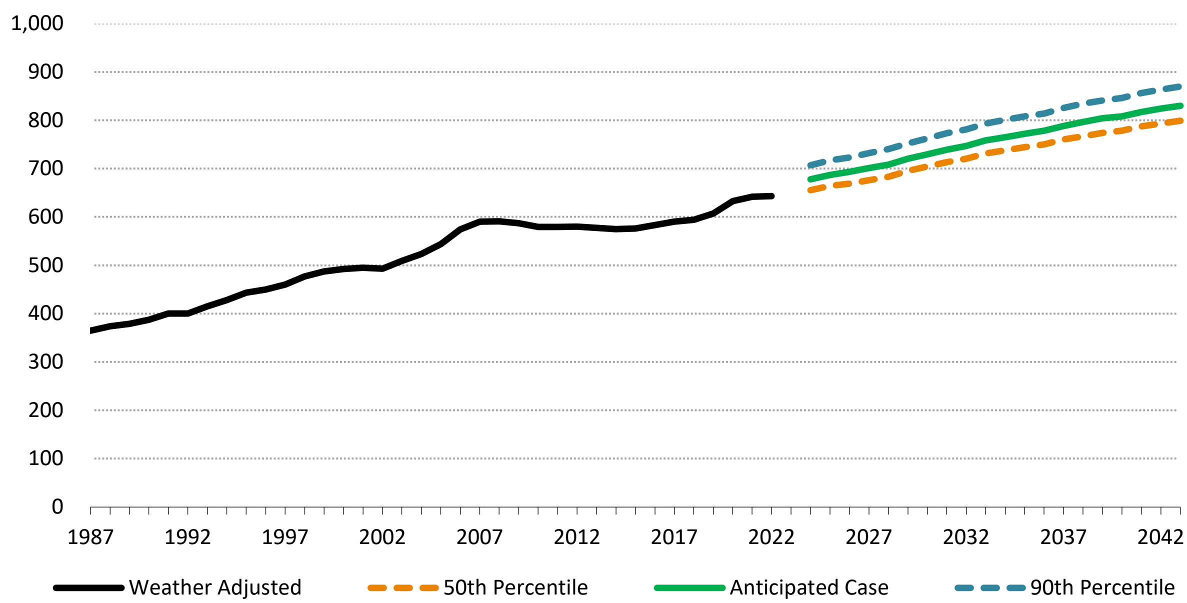



**Figure 7. Forecast residential load (aMW)**

Sales to residential customers made up 31% of Idaho Power's system sales in 1992 and 37% of system sales in 2022. The number of residential customers is projected to increase to nearly 724,000 by December 2043.

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 UPC 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 UPC to stabilize through 2007. However, conservation efforts have placed downward pressure on residential UPC since that point. This trend is expected to continue, declining at 0.6% annually over the 2024–2043 planning period, as total residential UPC is expected to decrease to approximately 9,700 kWh by 2043. Residential UPC is shown in Figure 8.

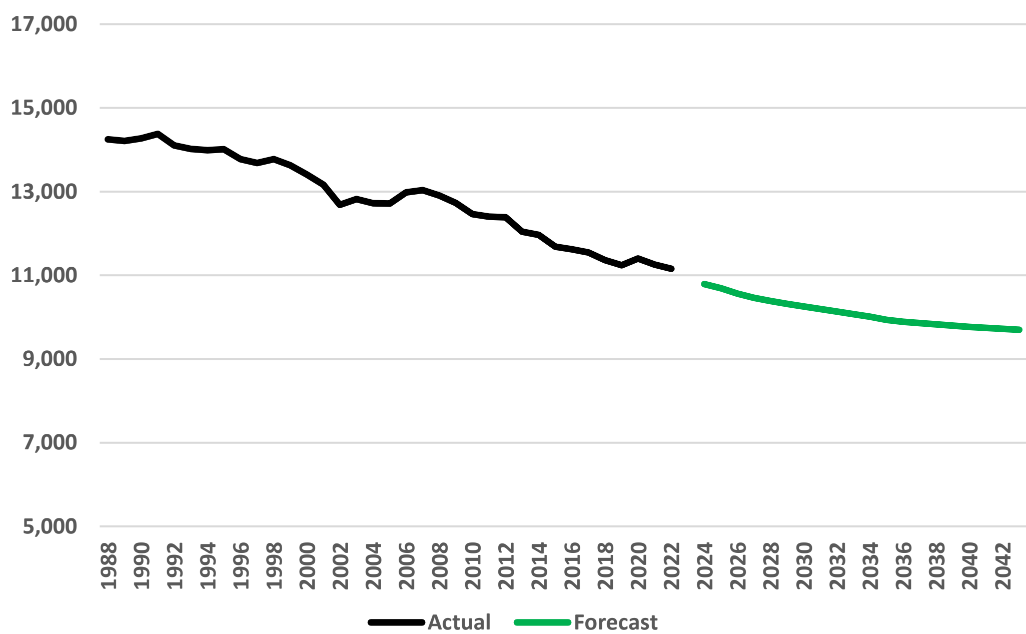



**Figure 8. Forecast residential UPC (weather-adjusted kWh)**

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 2024 to 2043 shows an average annual compound growth rate of 1.6% as shown in Figure 9.

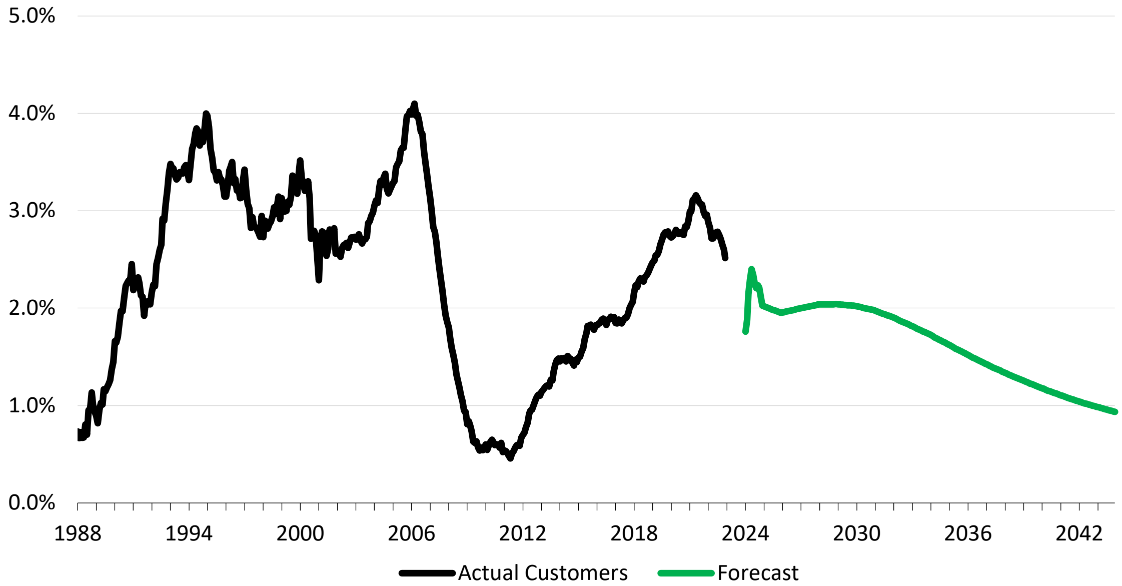



**Figure 9. Residential customer growth rates (12-month change)**

Final sales to residential retail customers can be framed as an equation that considers several factors affecting electricity sales to the residential sector. These factors include, but are not limited to: 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.

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.

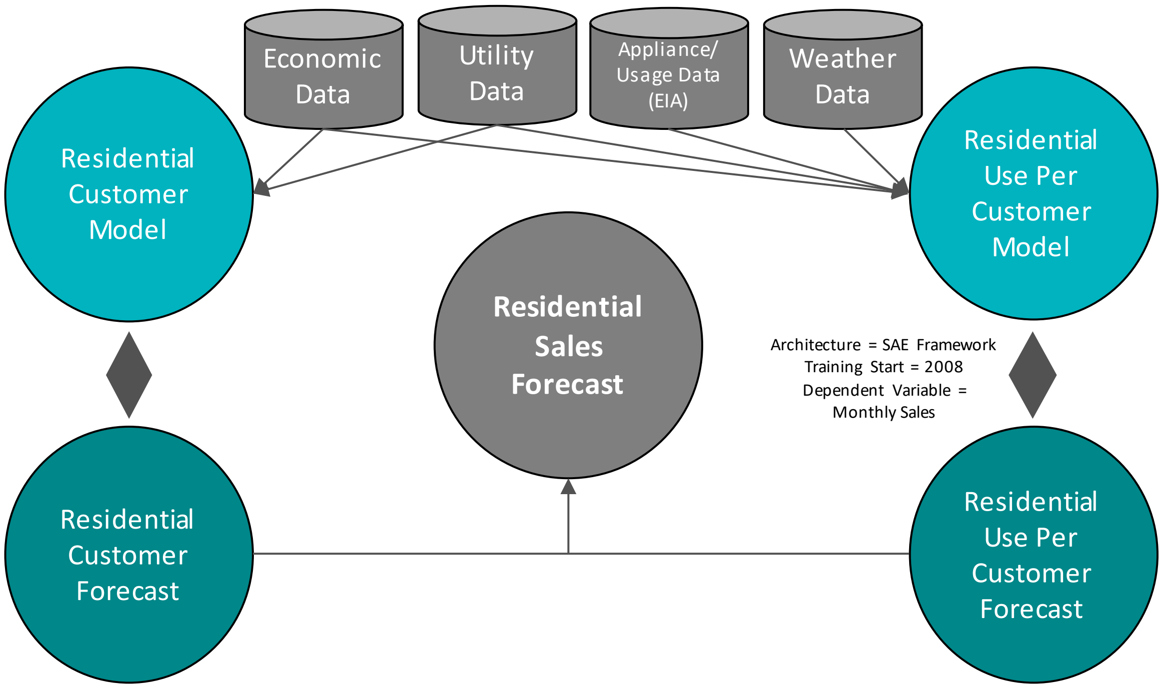



**Figure 10. Residential sales forecast methodology framework**

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 70$^{th}$-percentile (anticipated case) scenario, commercial load is projected to increase from 500 aMW in 2024 to 586 aMW in 2043 (Table 8). The average annual compound growth rate of the commercial load in the anticipated scenario is 0.8% during the forecast period. The commercial load in the 50$^{th}$-percentile scenario is projected to increase from 492 aMW in 2024 to 576 aMW in 2043, also at an average annual compound growth rate of 0.8%. The commercial load in the 90$^{th}$-percentile scenario is projected to increase from 509 aMW in 2024 to 599 aMW in 2043, an average annual compound growth rate of 0.9%. The commercial load forecast scenarios are illustrated in Figure 11.

**Table 8. Commercial load growth (aMW)**

| Growth | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 90th Percentile | 509 | 524 | 548 | 599 | 0.9% |
| Anticipated Case | 500 | 515 | 537 | 586 | 0.8% |
| 50th Percentile | 492 | 506 | 528 | 576 | 0.8% |

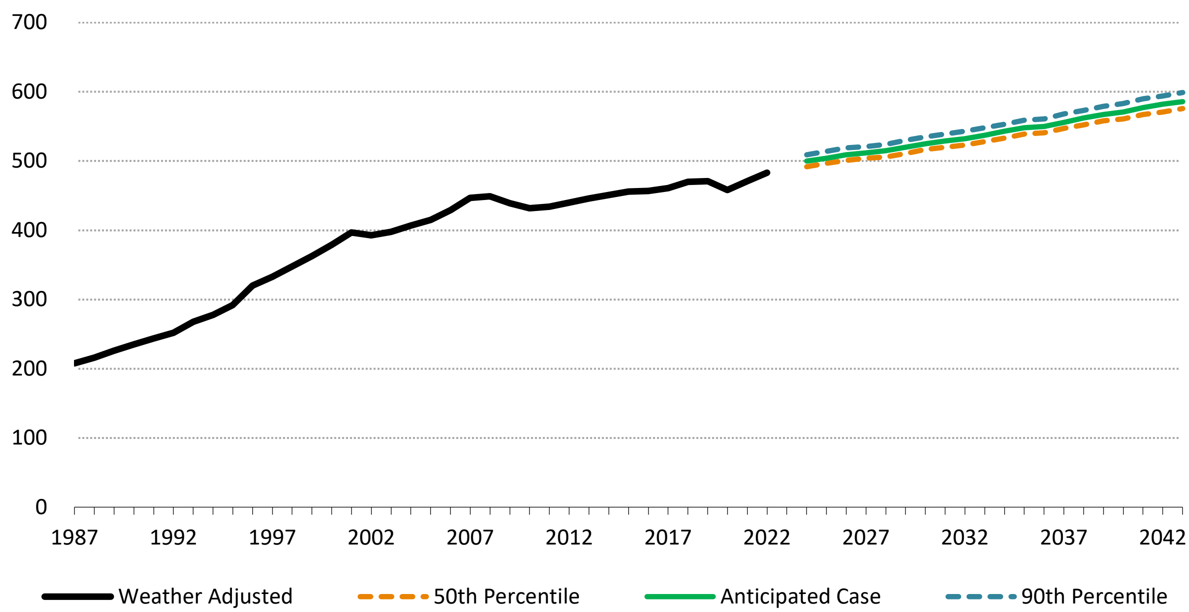



**Figure 11. Forecast commercial load (aMW)**

With a customer base of over 77,300, 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 2022 billed energy sales.

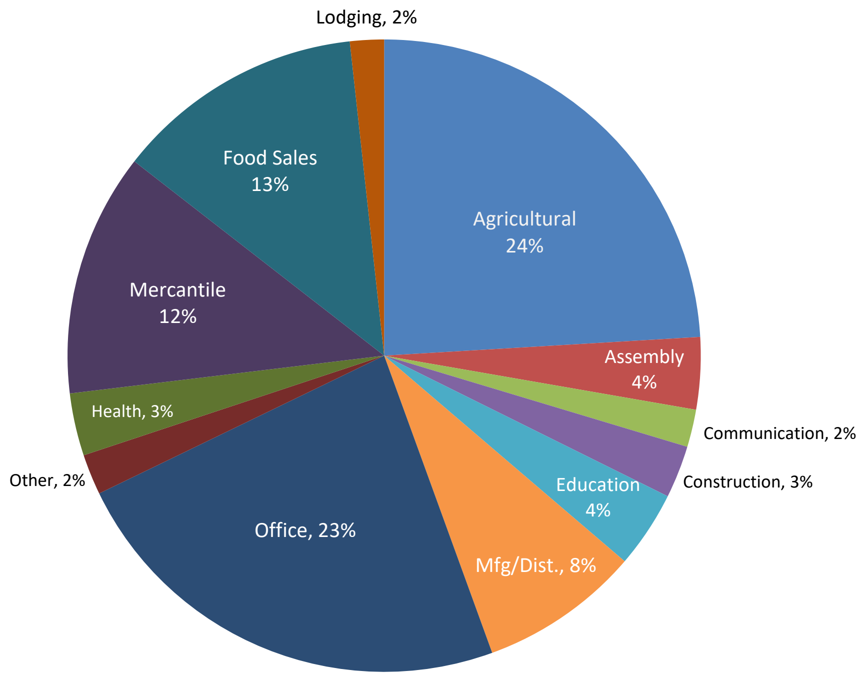



**Figure 12. Commercial building share—energy use**

As indicated in Figure 12, agricultural-related and office-oriented operations represent approximately 50% of the commercial sector. The mercantile group continues a contraction trend due to consolidation and online/home delivery substitution, with substitutive growth coming to manufacturing/distribution. Growth continues within the construction group, albeit slowing in the most recent period as new single-housing unit share has diminished in favor of multi-family housing as well as inventory overhang within the market. The health and education group consolidation that had previously exhibited contraction in share and growth rates has diminished and stabilized as of the last IRP. As referenced above, the online share of the supply chain has resulted in continued growth in warehouse and distribution customers, reflected in the manufacturing/distribution group. Agricultural and manufacturing operations continue to migrate to the service territory and flourish with average long-term growth rates of 1.6% and 2.9%, respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.5%, reaching approximately 105,200 customers by December 2043. In 1992, customers in the commercial category consumed approximately 19% of Idaho Power system sales, growing to 27% by 2022.

Figure 13 shows historical and forecast average UPC for the entire category. The commercial UPC metric in Figure 13 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy UPC, nonetheless it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,800 kWh and has declined at approximately 1% compounded annually to 2022. The UPC is forecast to decrease at an annual rate of 0.7% over the planning period. For this category, common elements that drive use down include a shift toward service-based over industrial customer composition, adoption of energy efficiency technology, and electricity prices.

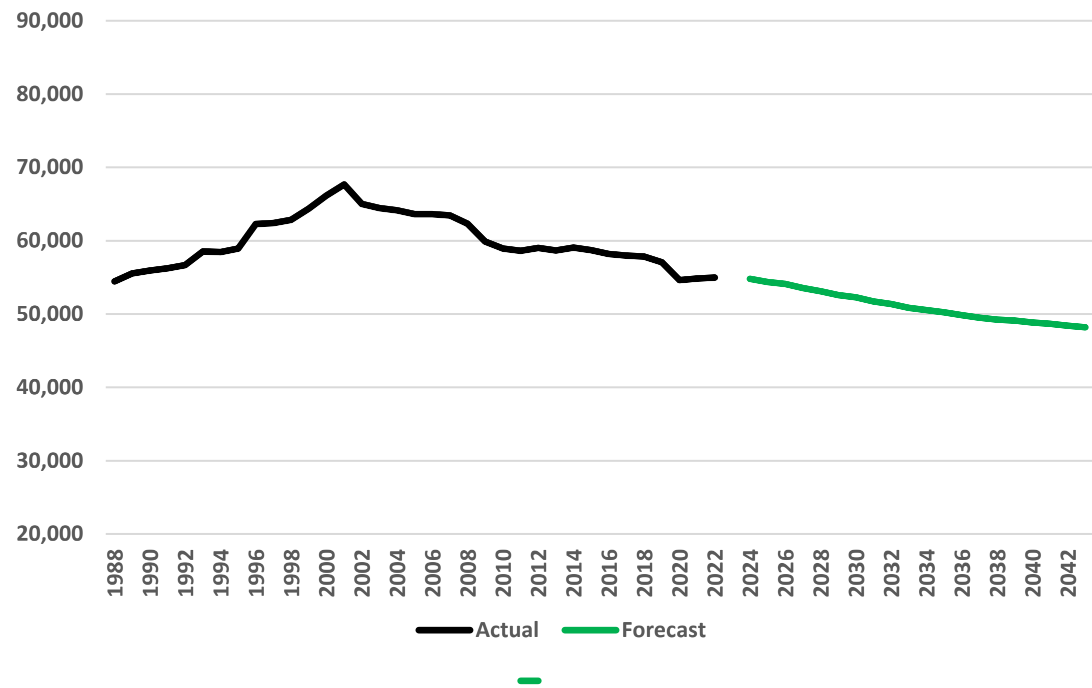



**Figure 13.** **Forecast commercial UPC (weather-adjusted kWh)**

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2022 UPC for each segment relative to the 2016 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.

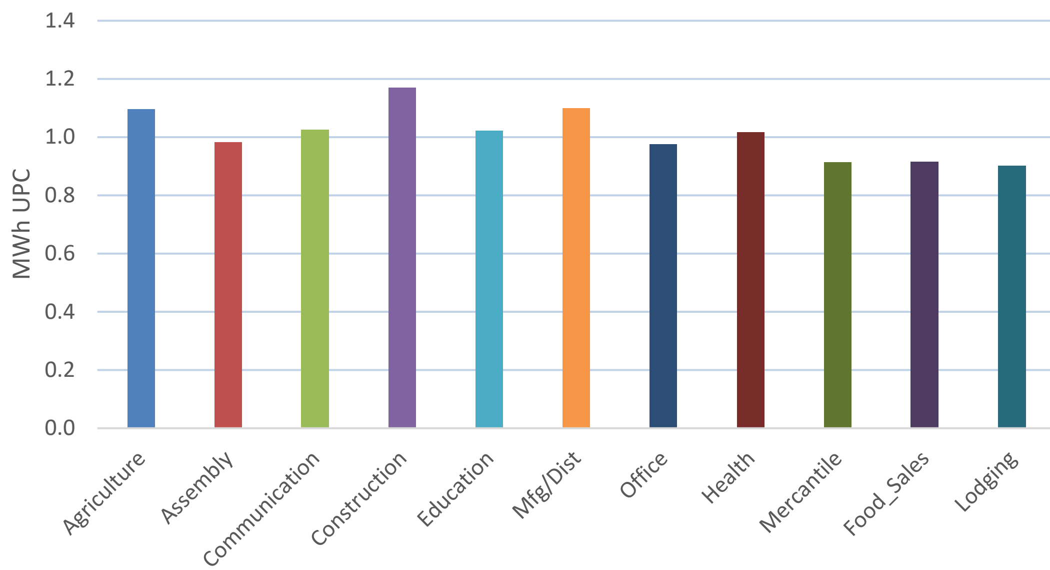



**Figure 14. Commercial categories UPC, 2022 relative to 2016**

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 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 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 2022, the number of industrial customers had risen to 125, 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 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 ESA customers and are addressed in the Additional Firm Load section of this document.

In the anticipated forecast, industrial load grows from 311 aMW in 2024 to 400 aMW in 2043, an average annual growth rate of 1.3% (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 50$^{th}$- and 90$^{th}$-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 | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| Anticipated Case | 311 | 326 | 346 | 400 | 1.3% |

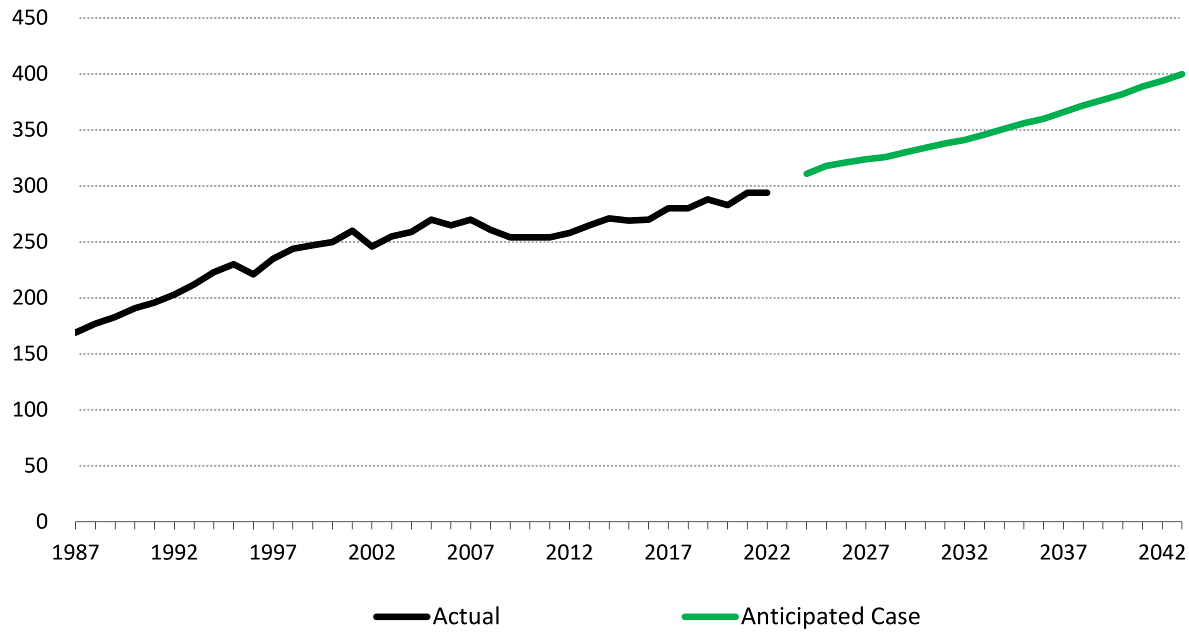



**Figure 15. Forecast industrial load (aMW)**

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 (causal) 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 2022 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 (39%), followed by dairy (19%) and construction-related (7%). The categorization scheme includes a range of service-providing industrial building types (assembly, lodging, 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.

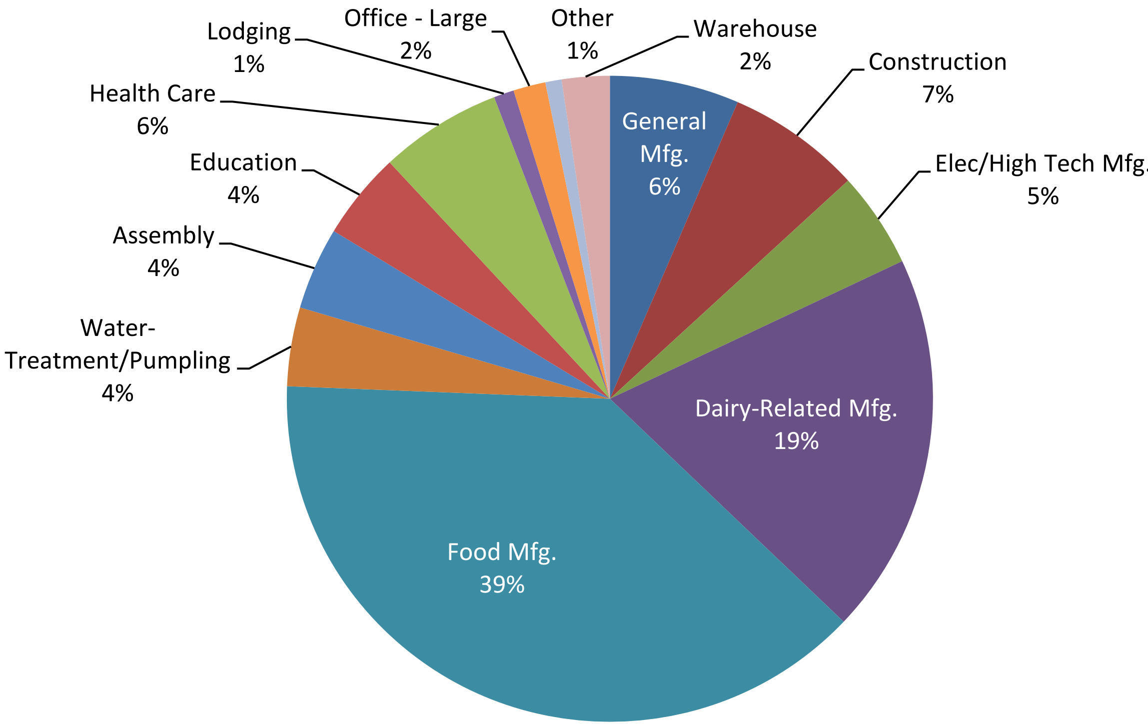



**Figure 16. Industrial electricity consumption by industry group (based on 2022 sales)**

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.

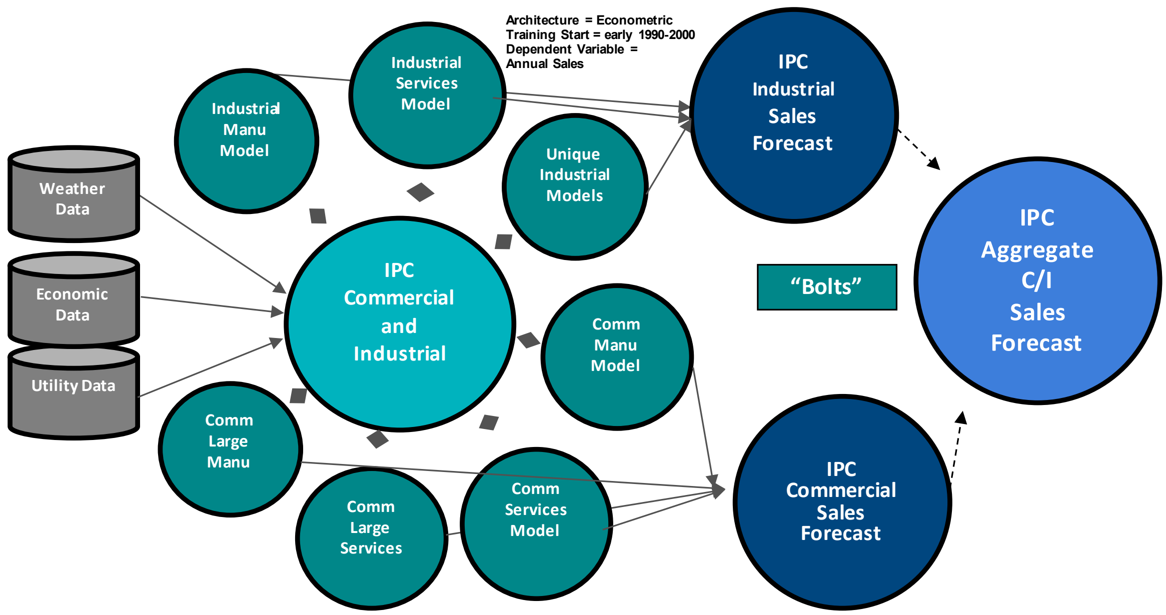



**Figure 17. Commercial and industrial sales forecast methodology**

## Irrigation

The irrigation category is comprised of agricultural irrigation service customers. Service under this schedule is applicable to 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 70th-percentile (anticipated) irrigation load is forecast to increase slowly from 240 aMW in 2024 to 268 aMW in 2043, an average annual compound growth rate of 0.6%. In the 50th-percentile scenario, irrigation load is projected to be 224 aMW in 2024 and 251 aMW in 2043, also at an average annual compound growth rate of 0.6%. In the 90th-percentile scenario, irrigation load is projected to be 260 aMW in 2024 and 288 aMW in 2043, an average annual compound growth rate of 0.5%. All irrigation load growth scenarios forecast slower growth than the system from 2024 to 2043. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

**Table 10. Irrigation load growth (aMW)**

| Growth | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| 90th Percentile | 260 | 264 | 271 | 288 | 0.5% |
| Anticipated Case | 240 | 244 | 251 | 268 | 0.6% |
| 50th Percentile | 224 | 227 | 234 | 251 | 0.6% |

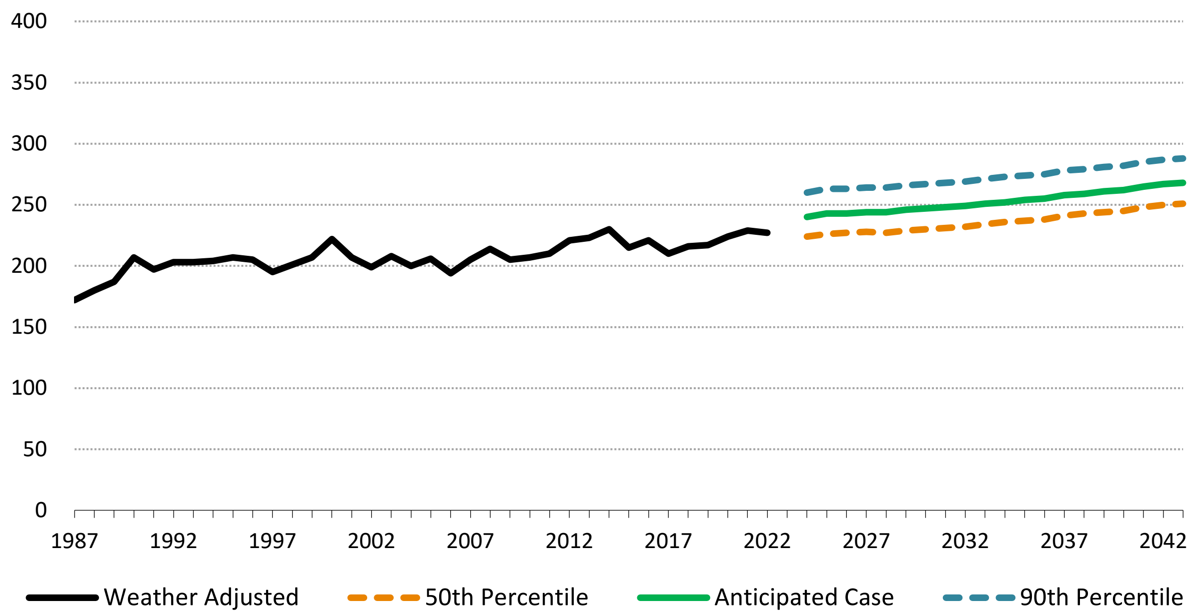



**Figure 18. Forecast irrigation load (aMW)**

The annual average loads in Table 10 and Figure 18 are calculated using 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 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 slight increase of forecasted sales over this period is due to the expected increase in customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers aiming 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 2023 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 2022, the irrigation proportion of system sales was 13% due to the much higher relative growth in other customer classes.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2022, the number of active irrigation accounts had increased to 20,936 and is projected to be nearly 25,900 at the end of the planning period in 2043.

As with other classes, average UPC 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 as customers are converting previously furrow-irrigated land to sprinkler irrigated land. The conversion rate is slow and the kWh UPC 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 to serve requests for electric service greater than 20 MW under an under a special contract, or ESA, schedule negotiated between Idaho Power and each large-power customer. The ESA and tariff schedule are approved by the appropriate state commission. An ESA allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

Individual energy and peak-demand forecasts are developed for ESA customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL; Brisbie, LLC (Meta Platforms, Inc.); and several anticipated new ESA customers. These ESA customers comprise the entire forecast category labeled "additional firm load".

In the anticipated forecast, additional firm load is expected to increase from 135 aMW in 2024 to 712 aMW in 2043, an average growth rate of 9.1% per year over the planning period (Table 11). The additional firm load energy and demand forecasts in the 50$^{th}$- and 90$^{th}$-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 | 2024 | 2028 | 2033 | 2043 | Annual Growth Rate 2024–2043 |
|---|---|---|---|---|---|
| Anticipated Case | 135 | 589 | 702 | 712 | 9.1% |

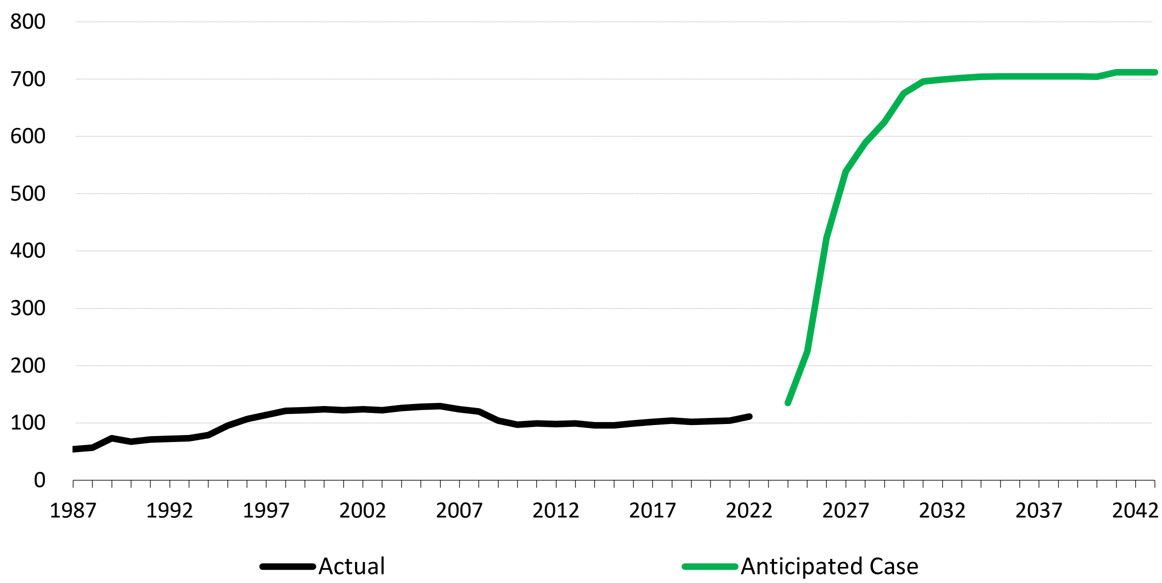



**Figure 19. Forecast additional firm load (aMW)**

### *Micron Technology*

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs more than 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, and corporate and general services. Micron Technology's electricity use is a function of the market demand for its products.

### *Simplot Fertilizer*

This facility named the Don Plant is located just outside Pocatello, Idaho. The Don Plant is one of four fertilizer manufacturing plants in the J.R. Simplot Company's Agribusiness Group. Vital to fertilizer production at the Don Plant is phosphate ore mined at Simplot's Smoky Canyon mine on the Idaho/Wyoming border. According to industry standards, the Don Plant is rated as one of the most cost-efficient fertilizer producers in North America. In total, J.R. Simplot Company employs 2,000–3,000 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 with over 4,000 employees.

### *Brisbie, LLC (Meta Platforms, Inc.)*

Idaho Power and Meta Platforms, Inc. (Meta) executed an ESA at the end of 2021, which is still pending commission approval at the time of this report. Meta has announced the construction of a new data center in Kuna, Idaho. With an estimated investment of $800 million, the Meta data center is projected to bring more than 1,200 jobs to Kuna during peak construction and 100 operational jobs. Meta plans to support 100% of its operations through the addition of new renewable resources connected to Idaho Power's system. The renewables support will be facilitated through a Clean Energy Your Way (CEYW) arrangement.

# 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 DOE and is consistent with the 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 homogenous residential sector.

While DOE data is available for the commercial sector, Idaho Power's test modeling of the data indicates 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, particularly for residential customers. While the current population of on-site generation customers is over 2% of the population of retail customers, recent adoption of solar is relatively strong for Idaho Power's service area.

The installation of generation and storage equipment at customer sites causes 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. The long-term sales forecast was adjusted downward to reflect the impact of the increase in the number customers with on-site generation, specifically solar generation, connecting to Idaho Power's system.

Schedules 6, 8, and 84 (net-metering) customer billing histories were compared to billing histories prior to customers becoming net-metering customers. 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 UPC sales impact per customer results in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2043, the annual residential sales forecast reduction was about 74 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, the continued technological advancement, limiting attributes of vehicle range refueling time, and charging availability and technology 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. Other data sources for monitoring the outlook for PEV adoption includes the DOE, R.L. Polk, and Moody's Analytics.

The evolution of the PEV market shows high adoption continues to be evident in warmer climates, high-density and affluent population centers. The Idaho Power forecast for PEVs shows 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

Existing and future demand response program impacts are not incorporated into the sales and load forecast. 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. A thorough description of Idaho Power's energy efficiency and demand response programs is included in *Appendix B—Demand-Side Management 2022 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 (2024–2043) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2023 IRP | 0.1% | -2.0% |
| Electricity—2021 IRP | 0.9% | -1.2% |
| Natural Gas | 0.3% | -1.7% |

*adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1987 to 2022 and over the forecast period 2024 to 2043. Both nominal and real prices are shown. In the 2023 IRP, nominal electricity prices are expected to climb to about 11.8 cents per kWh by the end of the forecast period in 2043. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 2% annually. In the 2021 IRP, nominal electricity prices were assumed to climb to about 13 cents per kWh by 2043, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of 1.2% annually.

The electricity price forecast used to prepare the sales and load forecast in the 2023 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2021 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2021 IRP sales and load forecast, the electricity price forecast used to prepare the 2023 IRP sales and load 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.

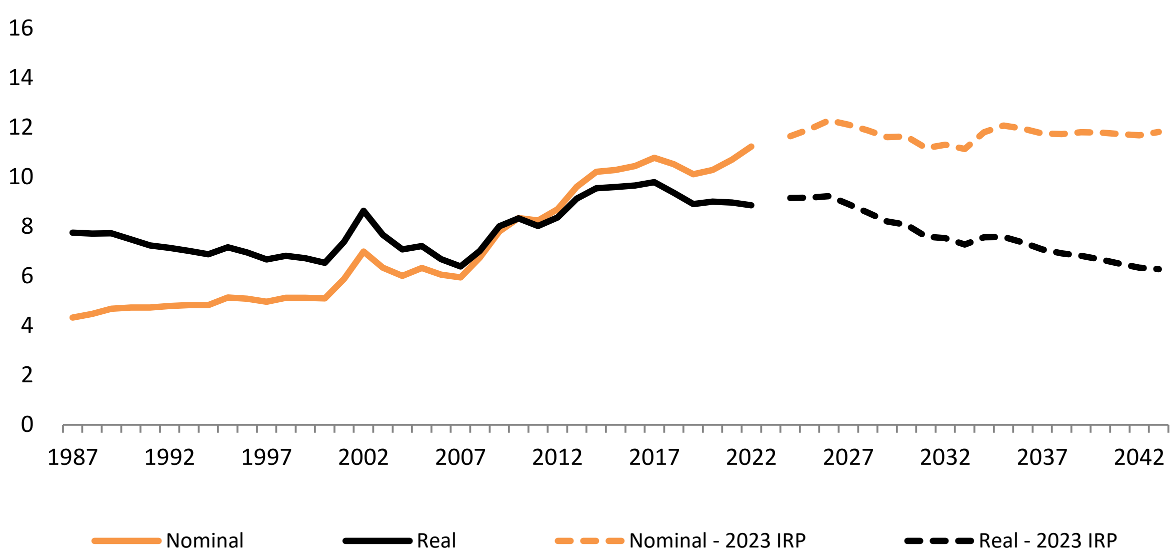



**Figure 20. Forecast residential electricity prices (cents per kWh)**

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 1987 to 2021 and forecast prices from 2024 to 2043. Nominal natural gas prices are expected to rise throughout the forecast period, growing at an average rate of 0.3% per year. Real natural gas prices (adjusted for inflation) are expected to decrease over the same period at an average rate of 1.7% annually.

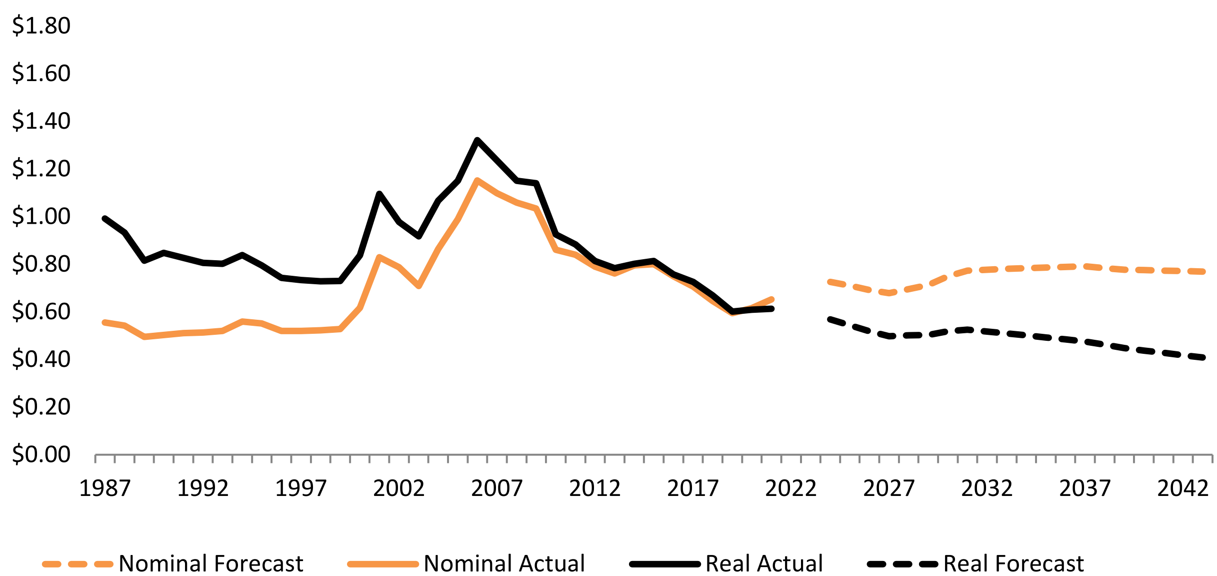



**Figure 21. Forecast residential natural gas prices (dollars per therm)**

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 2023 IRP price forecast, the long-term direction in real electricity prices and real natural gas prices (adjusted for inflation) is downward.

## 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. The most current system loss study was completed in 2023.

## 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 in its hourly load forecasting methodology. 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. It is important to note the monthly modeling mentioned drives the forecast used in the IRP. The hourly load forecast methodology described below simply allocates the monthly model regressions to each hour of the year.

### *Hourly Load Forecast Methodology*

The company believes it is prudent to maintain the integrity of the historic long-term forecasting methodologies. The company concluded in 2021 that the hourly forecast should use a neural network. A neural network utilizes the stability of monthly sales data to calibrate and ground the hourly data via monthly peak regressions. This neural network was developed under counsel with Itron Forecasting. The company ensured this methodology employs control and flexibility on the neural network while remaining highly transparent.

### *Technical Specifications of 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 an HDD or CDD 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.

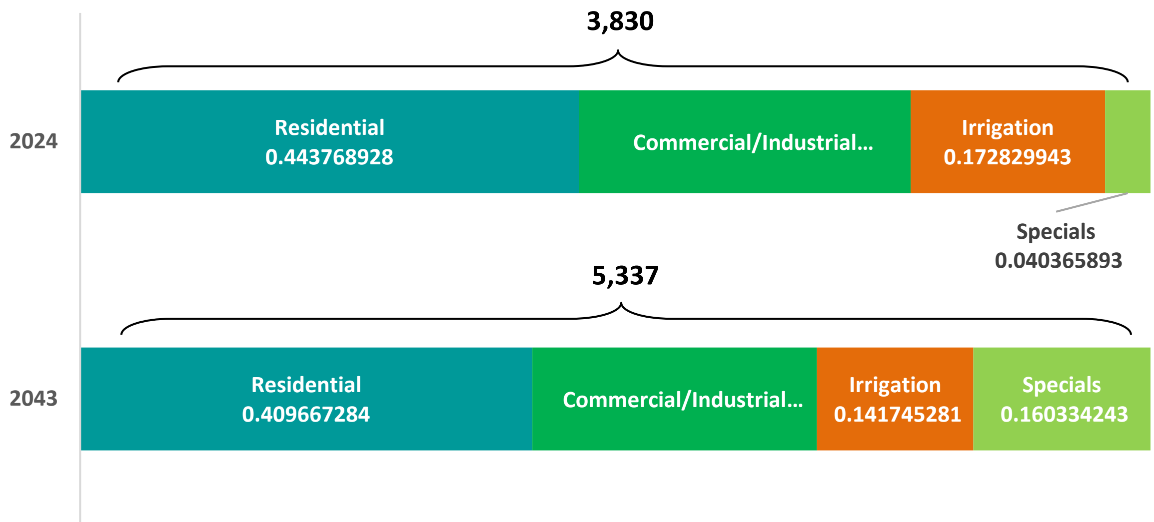
A distinct model is developed for each hour of the year to capture the full spectrum of temperature responsiveness. For each non-linear hourly model, an instantaneous derivative value is calculated along the curve to obtain the relationship of energy sales to temperature. A key initiative for Idaho Power 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 uses the 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 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 joined with the abovementioned typical meteorological year 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 by 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 shown in Figure 22.




*Total includes impact from losses

**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 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 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, 1982–2022 (weather adjusted)

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1982 | 7,820 | | 954 |
| 1983 | 8,045 | 2.9% | 978 |
| 1984 | 8,107 | 0.8% | 983 |
| 1985 | 8,256 | 1.8% | 1,003 |
| 1986 | 8,359 | 1.2% | 1,016 |
| 1987 | 8,499 | 1.7% | 1,033 |
| 1988 | 8,834 | 3.9% | 1,071 |
| 1989 | 9,201 | 4.2% | 1,117 |
| 1990 | 9,559 | 3.9% | 1,160 |
| 1991 | 9,741 | 1.9% | 1,182 |
| 1992 | 9,963 | 2.3% | 1,206 |
| 1993 | 10,274 | 3.1% | 1,250 |
| 1994 | 10,663 | 3.8% | 1,295 |
| 1995 | 11,137 | 4.4% | 1,351 |
| 1996 | 11,467 | 3.0% | 1,389 |
| 1997 | 11,755 | 2.5% | 1,427 |
| 1998 | 12,240 | 4.1% | 1,483 |
| 1999 | 12,548 | 2.5% | 1,522 |
| 2000 | 12,928 | 3.0% | 1,566 |
| 2001 | 13,062 | 1.0% | 1,580 |
| 2002 | 12,791 | -2.1% | 1,552 |
| 2003 | 13,140 | 2.7% | 1,592 |
| 2004 | 13,344 | 1.5% | 1,616 |
| 2005 | 13,707 | 2.7% | 1,667 |
| 2006 | 13,995 | 2.1% | 1,697 |
| 2007 | 14,389 | 2.8% | 1,745 |
| 2008 | 14,464 | 0.5% | 1,746 |
| 2009 | 13,986 | -3.3% | 1,697 |
| 2010 | 13,835 | -1.1% | 1,677 |
| 2011 | 13,860 | 0.2% | 1,684 |
| 2012 | 14,068 | 1.5% | 1,706 |
| 2013 | 14,076 | 0.1% | 1,720 |
| 2014 | 14,268 | 1.4% | 1,733 |

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2015 | 14,134 | -0.9% | 1,721 |
| 2016 | 14,296 | 1.1% | 1,740 |
| 2017 | 14,408 | 0.8% | 1,754 |
| 2018 | 14,579 | 1.2% | 1,777 |
| 2019 | 14,729 | 1.0% | 1,798 |
| 2020 | 14,884 | 1.1% | 1,815 |
| 2021 | 15,156 | 1.8% | 1,858 |
| 2022 | 15,351 | 1.3% | 1,877 |

**Company System Load**

**Projected Company System Sales and Load, 2024–2043**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2024 | 15,958 | 1.9% | 2,024 |
| 2025 | 16,577 | 3.9% | 2,141 |
| 2026 | 17,544 | 5.8% | 2,360 |
| 2027 | 18,464 | 5.2% | 2,495 |
| 2028 | 19,060 | 3.2% | 2,561 |
| 2029 | 19,514 | 2.4% | 2,622 |
| 2030 | 20,117 | 3.1% | 2,695 |
| 2031 | 20,461 | 1.7% | 2,737 |
| 2032 | 20,671 | 1.0% | 2,755 |
| 2033 | 20,840 | 0.8% | 2,784 |
| 2034 | 21,026 | 0.9% | 2,807 |
| 2035 | 21,186 | 0.8% | 2,827 |
| 2036 | 21,359 | 0.8% | 2,841 |
| 2037 | 21,515 | 0.7% | 2,868 |
| 2038 | 21,690 | 0.8% | 2,890 |
| 2039 | 21,863 | 0.8% | 2,912 |
| 2040 | 22,032 | 0.8% | 2,926 |
| 2041 | 22,251 | 1.0% | 2,960 |
| 2042 | 22,407 | 0.7% | 2,980 |
| 2043 | 22,561 | 0.7% | 2,999 |

## Residential Load
### Historical Residential Sales and Load, 1982–2022 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1982 | 216,696 | | 13,508 | 2,927 | | 337 |
| 1983 | 219,849 | 1.5% | 14,332 | 3,151 | 7.6% | 358 |
| 1984 | 222,695 | 1.3% | 14,005 | 3,119 | -1.0% | 355 |
| 1985 | 225,185 | 1.1% | 13,821 | 3,112 | -0.2% | 355 |
| 1986 | 227,081 | 0.8% | 14,073 | 3,196 | 2.7% | 365 |
| 1987 | 228,868 | 0.8% | 13,981 | 3,200 | 0.1% | 365 |
| 1988 | 230,771 | 0.8% | 14,251 | 3,289 | 2.8% | 374 |
| 1989 | 233,370 | 1.1% | 14,209 | 3,316 | 0.8% | 379 |
| 1990 | 238,117 | 2.0% | 14,271 | 3,398 | 2.5% | 387 |
| 1991 | 243,207 | 2.1% | 14,379 | 3,497 | 2.9% | 400 |
| 1992 | 249,767 | 2.7% | 14,102 | 3,522 | 0.7% | 400 |
| 1993 | 258,271 | 3.4% | 14,019 | 3,621 | 2.8% | 415 |
| 1994 | 267,854 | 3.7% | 13,992 | 3,748 | 3.5% | 428 |
| 1995 | 277,131 | 3.5% | 14,011 | 3,883 | 3.6% | 443 |
| 1996 | 286,227 | 3.3% | 13,774 | 3,943 | 1.5% | 450 |
| 1997 | 294,674 | 3.0% | 13,687 | 4,033 | 2.3% | 460 |
| 1998 | 303,300 | 2.9% | 13,778 | 4,179 | 3.6% | 477 |
| 1999 | 312,901 | 3.2% | 13,633 | 4,266 | 2.1% | 487 |
| 2000 | 322,402 | 3.0% | 13,411 | 4,324 | 1.4% | 492 |
| 2001 | 331,009 | 2.7% | 13,168 | 4,359 | 0.8% | 495 |
| 2002 | 339,764 | 2.6% | 12,687 | 4,311 | -1.1% | 493 |
| 2003 | 349,219 | 2.8% | 12,820 | 4,477 | 3.9% | 509 |
| 2004 | 360,462 | 3.2% | 12,725 | 4,587 | 2.5% | 523 |
| 2005 | 373,602 | 3.6% | 12,715 | 4,750 | 3.6% | 544 |
| 2006 | 387,707 | 3.8% | 12,983 | 5,033 | 6.0% | 574 |
| 2007 | 397,286 | 2.5% | 13,036 | 5,179 | 2.9% | 590 |
| 2008 | 402,520 | 1.3% | 12,905 | 5,194 | 0.3% | 591 |
| 2009 | 405,144 | 0.7% | 12,730 | 5,157 | -0.7% | 587 |
| 2010 | 407,551 | 0.6% | 12,463 | 5,079 | -1.5% | 579 |
| 2011 | 409,786 | 0.5% | 12,405 | 5,083 | 0.1% | 579 |
| 2012 | 413,610 | 0.9% | 12,390 | 5,124 | 0.8% | 580 |
| 2013 | 418,892 | 1.3% | 12,043 | 5,045 | -1.6% | 577 |
| 2014 | 425,036 | 1.5% | 11,965 | 5,086 | 0.8% | 575 |
| 2015 | 432,275 | 1.7% | 11,688 | 5,053 | -0.7% | 576 |
| 2016 | 440,362 | 1.9% | 11,627 | 5,120 | 1.3% | 583 |

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2017 | 448,800 | 1.9% | 11,546 | 5,182 | 1.2% | 590 |
| 2018 | 459,128 | 2.3% | 11,361 | 5,216 | 0.7% | 594 |
| 2019 | 471,298 | 2.7% | 11,239 | 5,297 | 1.5% | 607 |
| 2020 | 484,433 | 2.8% | 11,401 | 5,523 | 4.3% | 633 |
| 2021 | 499,216 | 3.1% | 11,257 | 5,620 | 1.8% | 642 |
| 2022 | 512,803 | 2.7% | 11,151 | 5,718 | 1.8% | 643 |

**Projected Residential Sales and Load, 2024–2043**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2024 | 533,126 | 2.2% | 10,793 | 5,754 | 1.1% | 678 |
| 2025 | 543,708 | 2.0% | 10,690 | 5,812 | 1.0% | 687 |
| 2026 | 554,453 | 2.0% | 10,563 | 5,857 | 0.8% | 693 |
| 2027 | 565,646 | 2.0% | 10,464 | 5,919 | 1.1% | 701 |
| 2028 | 577,181 | 2.0% | 10,388 | 5,996 | 1.3% | 708 |
| 2029 | 588,906 | 2.0% | 10,322 | 6,079 | 1.4% | 720 |
| 2030 | 600,677 | 2.0% | 10,254 | 6,159 | 1.3% | 729 |
| 2031 | 612,333 | 1.9% | 10,196 | 6,243 | 1.4% | 739 |
| 2032 | 623,729 | 1.9% | 10,137 | 6,323 | 1.3% | 747 |
| 2033 | 634,783 | 1.8% | 10,078 | 6,398 | 1.2% | 758 |
| 2034 | 645,419 | 1.7% | 10,011 | 6,461 | 1.0% | 765 |
| 2035 | 655,575 | 1.6% | 9,939 | 6,516 | 0.8% | 772 |
| 2036 | 665,243 | 1.5% | 9,893 | 6,581 | 1.0% | 778 |
| 2037 | 674,440 | 1.4% | 9,862 | 6,651 | 1.1% | 788 |
| 2038 | 683,192 | 1.3% | 9,833 | 6,718 | 1.0% | 796 |
| 2039 | 691,515 | 1.2% | 9,801 | 6,778 | 0.9% | 804 |
| 2040 | 699,424 | 1.1% | 9,770 | 6,833 | 0.8% | 808 |
| 2041 | 706,941 | 1.1% | 9,744 | 6,888 | 0.8% | 817 |
| 2042 | 714,108 | 1.0% | 9,722 | 6,943 | 0.8% | 824 |
| 2043 | 720,959 | 1.0% | 9,700 | 6,993 | 0.7% | 830 |

## Commercial Load

### Historical Commercial Sales and Load, 1982–2022 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1982 | 30,167 | | 54,137 | 1,633 | | 186 |
| 1983 | 30,776 | 2.0% | 52,637 | 1,620 | -0.8% | 185 |
| 1984 | 31,554 | 2.5% | 53,650 | 1,693 | 4.5% | 193 |
| 1985 | 32,418 | 2.7% | 54,285 | 1,760 | 4.0% | 201 |
| 1986 | 33,208 | 2.4% | 54,057 | 1,795 | 2.0% | 205 |
| 1987 | 33,975 | 2.3% | 53,611 | 1,821 | 1.5% | 208 |
| 1988 | 34,723 | 2.2% | 54,465 | 1,891 | 3.8% | 216 |
| 1989 | 35,638 | 2.6% | 55,525 | 1,979 | 4.6% | 226 |
| 1990 | 36,785 | 3.2% | 55,940 | 2,058 | 4.0% | 235 |
| 1991 | 37,922 | 3.1% | 56,243 | 2,133 | 3.7% | 244 |
| 1992 | 39,022 | 2.9% | 56,674 | 2,212 | 3.7% | 252 |
| 1993 | 40,047 | 2.6% | 58,522 | 2,344 | 6.0% | 268 |
| 1994 | 41,629 | 4.0% | 58,445 | 2,433 | 3.8% | 278 |
| 1995 | 43,165 | 3.7% | 58,918 | 2,543 | 4.5% | 292 |
| 1996 | 44,995 | 4.2% | 62,292 | 2,803 | 10.2% | 320 |
| 1997 | 46,819 | 4.1% | 62,380 | 2,921 | 4.2% | 333 |
| 1998 | 48,404 | 3.4% | 62,833 | 3,041 | 4.1% | 348 |
| 1999 | 49,430 | 2.1% | 64,354 | 3,181 | 4.6% | 363 |
| 2000 | 50,117 | 1.4% | 66,141 | 3,315 | 4.2% | 379 |
| 2001 | 51,501 | 2.8% | 67,665 | 3,485 | 5.1% | 397 |
| 2002 | 52,915 | 2.7% | 65,004 | 3,440 | -1.3% | 393 |
| 2003 | 54,194 | 2.4% | 64,459 | 3,493 | 1.6% | 398 |
| 2004 | 55,577 | 2.6% | 64,160 | 3,566 | 2.1% | 407 |
| 2005 | 57,145 | 2.8% | 63,620 | 3,636 | 2.0% | 415 |
| 2006 | 59,050 | 3.3% | 63,622 | 3,757 | 3.3% | 429 |
| 2007 | 61,640 | 4.4% | 63,448 | 3,911 | 4.1% | 447 |
| 2008 | 63,492 | 3.0% | 62,295 | 3,955 | 1.1% | 449 |
| 2009 | 64,151 | 1.0% | 59,859 | 3,840 | -2.9% | 439 |
| 2010 | 64,421 | 0.4% | 58,905 | 3,795 | -1.2% | 432 |
| 2011 | 64,921 | 0.8% | 58,602 | 3,805 | 0.3% | 434 |
| 2012 | 65,599 | 1.0% | 59,032 | 3,872 | 1.8% | 440 |
| 2013 | 66,357 | 1.2% | 58,682 | 3,894 | 0.6% | 446 |
| 2014 | 67,113 | 1.1% | 59,057 | 3,963 | 1.8% | 451 |
| 2015 | 68,000 | 1.3% | 58,722 | 3,993 | 0.7% | 456 |

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2016 | 68,883 | 1.3% | 58,190 | 4,008 | 0.4% | 457 |
| 2017 | 69,850 | 1.4% | 57,964 | 4,049 | 1.0% | 461 |
| 2018 | 71,104 | 1.8% | 57,839 | 4,113 | 1.6% | 470 |
| 2019 | 72,332 | 1.7% | 57,034 | 4,125 | 0.3% | 471 |
| 2020 | 73,702 | 1.9% | 54,610 | 4,025 | -2.4% | 458 |
| 2021 | 75,282 | 2.1% | 54,826 | 4,127 | 2.5% | 471 |
| 2022 | 76,672 | 1.8% | 54,983 | 4,216 | 2.1% | 483 |

### Projected Commercial Sales and Load, 2024–2043

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2024 | 78,882 | 1.4% | 54,802 | 4,323 | 1.3% | 500 |
| 2025 | 79,984 | 1.4% | 54,353 | 4,347 | 0.6% | 504 |
| 2026 | 81,175 | 1.5% | 54,083 | 4,390 | 1.0% | 509 |
| 2027 | 82,419 | 1.5% | 53,521 | 4,411 | 0.5% | 512 |
| 2028 | 83,738 | 1.6% | 53,094 | 4,446 | 0.8% | 515 |
| 2029 | 85,121 | 1.7% | 52,569 | 4,475 | 0.6% | 520 |
| 2030 | 86,551 | 1.7% | 52,271 | 4,524 | 1.1% | 525 |
| 2031 | 88,012 | 1.7% | 51,706 | 4,551 | 0.6% | 529 |
| 2032 | 89,487 | 1.7% | 51,348 | 4,595 | 1.0% | 532 |
| 2033 | 90,965 | 1.7% | 50,853 | 4,626 | 0.7% | 537 |
| 2034 | 92,433 | 1.6% | 50,520 | 4,670 | 0.9% | 543 |
| 2035 | 93,885 | 1.6% | 50,244 | 4,717 | 1.0% | 548 |
| 2036 | 95,314 | 1.5% | 49,820 | 4,749 | 0.7% | 550 |
| 2037 | 96,718 | 1.5% | 49,493 | 4,787 | 0.8% | 556 |
| 2038 | 98,098 | 1.4% | 49,253 | 4,832 | 0.9% | 562 |
| 2039 | 99,452 | 1.4% | 49,088 | 4,882 | 1.0% | 567 |
| 2040 | 100,781 | 1.3% | 48,855 | 4,924 | 0.9% | 571 |
| 2041 | 102,086 | 1.3% | 48,658 | 4,967 | 0.9% | 577 |
| 2042 | 103,368 | 1.3% | 48,409 | 5,004 | 0.7% | 582 |
| 2043 | 104,630 | 1.2% | 48,177 | 5,041 | 0.7% | 586 |

**Irrigation Load**

**Historical Irrigation Sales and Load, 1982–2022 (weather adjusted)**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1982 | 11,312 | | 152,949 | 1,730 | | 198 |
| 1983 | 11,133 | -1.6% | 148,748 | 1,656 | -4.3% | 190 |
| 1984 | 11,375 | 2.2% | 136,037 | 1,547 | -6.6% | 175 |
| 1985 | 11,576 | 1.8% | 134,360 | 1,555 | 0.5% | 176 |
| 1986 | 11,308 | -2.3% | 135,238 | 1,529 | -1.7% | 175 |
| 1987 | 11,254 | -0.5% | 133,394 | 1,501 | -1.8% | 172 |
| 1988 | 11,378 | 1.1% | 138,651 | 1,578 | 5.1% | 180 |
| 1989 | 11,957 | 5.1% | 137,247 | 1,641 | 4.0% | 187 |
| 1990 | 12,340 | 3.2% | 147,161 | 1,816 | 10.7% | 207 |
| 1991 | 12,484 | 1.2% | 138,688 | 1,731 | -4.7% | 197 |
| 1992 | 12,809 | 2.6% | 138,914 | 1,779 | 2.8% | 203 |
| 1993 | 13,078 | 2.1% | 135,086 | 1,767 | -0.7% | 203 |
| 1994 | 13,559 | 3.7% | 132,262 | 1,793 | 1.5% | 204 |
| 1995 | 13,679 | 0.9% | 132,474 | 1,812 | 1.0% | 207 |
| 1996 | 14,074 | 2.9% | 127,844 | 1,799 | -0.7% | 205 |
| 1997 | 14,383 | 2.2% | 118,942 | 1,711 | -4.9% | 195 |
| 1998 | 14,695 | 2.2% | 119,947 | 1,763 | 3.0% | 201 |
| 1999 | 14,912 | 1.5% | 122,035 | 1,820 | 3.2% | 207 |
| 2000 | 15,253 | 2.3% | 128,235 | 1,956 | 7.5% | 222 |
| 2001 | 15,522 | 1.8% | 116,730 | 1,812 | -7.4% | 207 |
| 2002 | 15,840 | 2.0% | 110,152 | 1,745 | -3.7% | 199 |
| 2003 | 16,020 | 1.1% | 113,351 | 1,816 | 4.1% | 208 |
| 2004 | 16,297 | 1.7% | 108,374 | 1,766 | -2.7% | 200 |
| 2005 | 16,936 | 3.9% | 106,011 | 1,795 | 1.7% | 206 |
| 2006 | 17,062 | 0.7% | 99,145 | 1,692 | -5.8% | 194 |
| 2007 | 17,001 | -0.4% | 105,373 | 1,791 | 5.9% | 205 |
| 2008 | 17,428 | 2.5% | 108,565 | 1,892 | 5.6% | 214 |
| 2009 | 17,708 | 1.6% | 101,586 | 1,799 | -4.9% | 205 |
| 2010 | 17,846 | 0.8% | 102,150 | 1,823 | 1.3% | 207 |
| 2011 | 18,292 | 2.5% | 100,382 | 1,836 | 0.7% | 210 |
| 2012 | 18,675 | 2.1% | 103,772 | 1,938 | 5.5% | 221 |
| 2013 | 19,017 | 1.8% | 102,889 | 1,957 | 1.0% | 223 |
| 2014 | 19,328 | 1.6% | 104,262 | 2,015 | 3.0% | 230 |
| 2015 | 19,756 | 2.2% | 95,494 | 1,887 | -6.4% | 215 |

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2016 | 20,042 | 1.4% | 96,629 | 1,937 | 2.7% | 221 |
| 2017 | 20,246 | 1.0% | 90,202 | 1,826 | -5.7% | 210 |
| 2018 | 20,459 | 1.1% | 92,540 | 1,893 | 3.7% | 216 |
| 2019 | 20,566 | 0.5% | 91,922 | 1,890 | -0.1% | 217 |
| 2020 | 20,804 | 1.2% | 94,667 | 1,969 | 4.2% | 224 |
| 2021 | 21,066 | 1.3% | 91,979 | 1,938 | -1.6% | 229 |
| 2022 | 21,324 | 1.2% | 89,590 | 1,910 | -1.4% | 227 |

**Projected Irrigation Sales and Load, 2024–2043**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2024 | 21,747 | 1.2% | 90,344 | 1,965 | 1.8% | 240 |
| 2025 | 21,997 | 1.1% | 90,140 | 1,983 | 0.9% | 243 |
| 2026 | 22,249 | 1.1% | 89,185 | 1,984 | 0.1% | 243 |
| 2027 | 22,498 | 1.1% | 88,598 | 1,993 | 0.5% | 244 |
| 2028 | 22,750 | 1.1% | 87,821 | 1,998 | 0.2% | 244 |
| 2029 | 22,999 | 1.1% | 87,110 | 2,003 | 0.3% | 246 |
| 2030 | 23,250 | 1.1% | 86,619 | 2,014 | 0.5% | 247 |
| 2031 | 23,502 | 1.1% | 86,151 | 2,025 | 0.5% | 248 |
| 2032 | 23,751 | 1.1% | 85,746 | 2,037 | 0.6% | 249 |
| 2033 | 24,002 | 1.1% | 85,405 | 2,050 | 0.7% | 251 |
| 2034 | 24,253 | 1.0% | 85,104 | 2,064 | 0.7% | 252 |
| 2035 | 24,502 | 1.0% | 84,841 | 2,079 | 0.7% | 254 |
| 2036 | 24,757 | 1.0% | 84,585 | 2,094 | 0.7% | 255 |
| 2037 | 25,007 | 1.0% | 84,363 | 2,110 | 0.7% | 258 |
| 2038 | 25,254 | 1.0% | 84,148 | 2,125 | 0.7% | 259 |
| 2039 | 25,505 | 1.0% | 83,936 | 2,141 | 0.7% | 261 |
| 2040 | 25,754 | 1.0% | 83,732 | 2,156 | 0.7% | 262 |
| 2041 | 26,006 | 1.0% | 83,524 | 2,172 | 0.7% | 265 |
| 2042 | 26,257 | 1.0% | 83,318 | 2,188 | 0.7% | 267 |
| 2043 | 26,508 | 1.0% | 83,095 | 2,203 | 0.7% | 268 |

## Industrial Load

### Historical Industrial Sales and Load, 1982–2022 (not weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1982 | 122 | | 9,504,283 | 1,162 | | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | -1.1% | 18,597,050 | 2,230 | -0.1% | 254 |
| 2012 | 115 | -4.2% | 19,757,921 | 2,271 | 1.8% | 258 |
| 2013 | 114 | -0.7% | 20,281,837 | 2,314 | 1.9% | 265 |
| 2014 | 113 | -0.7% | 20,863,653 | 2,363 | 2.1% | 271 |
| 2015 | 116 | 2.8% | 20,271,082 | 2,360 | -0.1% | 269 |
| 2016 | 118 | 1.4% | 19,993,955 | 2,361 | 0.0% | 270 |

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 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 |
| 2020 | 124 | -0.3% | 19,912,671 | 2,466 | -2.2% | 283 |
| 2021 | 124 | 0.0% | 20,671,453 | 2,560 | 3.8% | 294 |
| 2022 | 123 | -0.8% | 20,844,705 | 2,560 | 0.0% | 294 |

**Projected Industrial Sales and Load, 2024–2043**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2024 | 123 | 0.8% | 22,202,622 | 2,731 | 2.5% | 311 |
| 2025 | 124 | 0.8% | 22,422,106 | 2,780 | 1.8% | 318 |
| 2026 | 124 | 0.0% | 22,646,315 | 2,808 | 1.0% | 321 |
| 2027 | 125 | 0.8% | 22,681,295 | 2,835 | 1.0% | 324 |
| 2028 | 126 | 0.8% | 22,710,399 | 2,862 | 0.9% | 326 |
| 2029 | 128 | 1.6% | 22,584,636 | 2,891 | 1.0% | 330 |
| 2030 | 130 | 1.6% | 22,479,994 | 2,922 | 1.1% | 334 |
| 2031 | 130 | 0.0% | 22,745,901 | 2,957 | 1.2% | 338 |
| 2032 | 131 | 0.8% | 22,833,038 | 2,991 | 1.2% | 341 |
| 2033 | 131 | 0.0% | 23,126,588 | 3,030 | 1.3% | 346 |
| 2034 | 131 | 0.0% | 23,445,984 | 3,071 | 1.4% | 351 |
| 2035 | 132 | 0.8% | 23,592,069 | 3,114 | 1.4% | 356 |
| 2036 | 133 | 0.8% | 23,742,442 | 3,158 | 1.4% | 360 |
| 2037 | 134 | 0.8% | 23,895,073 | 3,202 | 1.4% | 366 |
| 2038 | 135 | 0.7% | 24,076,426 | 3,250 | 1.5% | 372 |
| 2039 | 135 | 0.0% | 24,447,379 | 3,300 | 1.5% | 377 |
| 2040 | 136 | 0.7% | 24,636,813 | 3,351 | 1.5% | 382 |
| 2041 | 138 | 1.5% | 24,640,741 | 3,400 | 1.5% | 389 |
| 2042 | 138 | 0.0% | 25,003,264 | 3,450 | 1.5% | 394 |
| 2043 | 139 | 0.7% | 25,188,594 | 3,501 | 1.5% | 400 |

## Additional Firm Sales and Load

### Historical Additional Firm Sales and Load, 1982–2022

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1982 | 367 | | 39 |
| 1983 | 425 | 15.7% | 45 |
| 1984 | 466 | 9.7% | 50 |
| 1985 | 471 | 1.1% | 50 |
| 1986 | 482 | 2.4% | 51 |
| 1987 | 502 | 4.2% | 54 |
| 1988 | 530 | 5.6% | 57 |
| 1989 | 671 | 26.5% | 73 |
| 1990 | 625 | -6.9% | 67 |
| 1991 | 661 | 5.8% | 71 |
| 1992 | 680 | 2.9% | 72 |
| 1993 | 689 | 1.3% | 73 |
| 1994 | 740 | 7.5% | 79 |
| 1995 | 878 | 18.6% | 95 |
| 1996 | 988 | 12.6% | 107 |
| 1997 | 1,048 | 6.0% | 114 |
| 1998 | 1,113 | 6.2% | 121 |
| 1999 | 1,121 | 0.8% | 122 |
| 2000 | 1,142 | 1.9% | 124 |
| 2001 | 1,118 | -2.1% | 122 |
| 2002 | 1,139 | 1.9% | 124 |
| 2003 | 1,120 | -1.7% | 122 |
| 2004 | 1,156 | 3.3% | 126 |
| 2005 | 1,175 | 1.6% | 128 |
| 2006 | 1,189 | 1.2% | 129 |
| 2007 | 1,141 | -4.0% | 124 |
| 2008 | 1,114 | -2.4% | 120 |
| 2009 | 965 | -13.4% | 104 |
| 2010 | 907 | -6.0% | 97 |
| 2011 | 906 | 0.0% | 99 |
| 2012 | 862 | -4.8% | 98 |
| 2013 | 867 | 0.5% | 99 |
| 2014 | 841 | -2.9% | 96 |
| 2015 | 842 | 0.1% | 96 |
| 2016 | 870 | 3.3% | 99 |

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2017 | 897 | 3.1% | 102 |
| 2018 | 910 | 1.4% | 104 |
| 2019 | 895 | -1.7% | 102 |
| 2020 | 900 | 0.6% | 103 |
| 2021 | 912 | 1.2% | 104 |
| 2022 | 947 | 3.8% | 111 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

## Projected Additional Firm Sales and Load, 2024–2043

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2024 | 1,186 | 7.6% | 135 |
| 2025 | 1,972 | 66.4% | 225 |
| 2026 | 3,702 | 87.7% | 423 |
| 2027 | 4,717 | 27.4% | 539 |
| 2028 | 5,175 | 9.7% | 589 |
| 2029 | 5,478 | 5.9% | 625 |
| 2030 | 5,910 | 7.9% | 675 |
| 2031 | 6,097 | 3.2% | 696 |
| 2032 | 6,141 | 0.7% | 699 |
| 2033 | 6,149 | 0.1% | 702 |
| 2034 | 6,171 | 0.4% | 704 |
| 2035 | 6,172 | 0.0% | 705 |
| 2036 | 6,193 | 0.3% | 705 |
| 2037 | 6,177 | -0.3% | 705 |
| 2038 | 6,176 | 0.0% | 705 |
| 2039 | 6,174 | 0.0% | 705 |
| 2040 | 6,184 | 0.2% | 704 |
| 2041 | 6,234 | 0.8% | 712 |
| 2042 | 6,234 | 0.0% | 712 |
| 2043 | 6,234 | 0.0% | 712 |

*Includes Micron Technology, Simplot Fertilizer, and the INL


September 2023

# IRP

INTEGRATED RESOURCE PLAN

APPENDIX B: **DSM ANNUAL REPORT**

IDAHO POWER®

## 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 remains one of the top-ranked utilities and ranked #3 in the West Midsize Segment of the *J.D. Power 2022 Electric Utility Residential Customer Satisfaction Study*.

In 2022, Idaho Power achieved 169,889 megawatt-hours (MWh) or 19.4 average megawatts (aMW) of incremental energy efficiency savings, including Northwest Energy Efficiency Alliance (NEEA) estimated energy savings, which exceeded the economic technical achievable potential included in the *2021 Integrated Resource Plan* (IRP) of 139,826 MWh or 16 aMW. The 2022 savings represent enough energy to power approximately 14,900 average homes in Idaho Power's service area for one year.

The Commercial and Industrial (C&I) Energy Efficiency Program, which typically provides more than half of the portfolio savings, returned savings 14,218 MWh higher than in 2021. Consequently, the 2022 savings of 169,889 MWh, including the estimated savings from NEEA, increased by 26,968 MWh—a 19% year-over-year increase. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, were 145,440 MWh in 2022 and 126,102 MWh in 2021—a 15% year-over-year increase. Overall, 2022 was a less challenging year than 2021 with regard to energy efficiency program participation due to the easing of COVID-19 restrictions, but supply chain issues, higher labor and material costs, and the maturity of the residential lighting market continued to put downward pressure on program participation.

In 2022, the company's energy efficiency portfolio was cost-effective from both the utility cost test (UCT) and the total resource cost (TRC) test perspectives with ratios of 2.02 and 1.43, respectively. The portfolio was also cost-effective from the participant cost test (PCT) ratio, which was 2.01.

Energy efficiency and demand response are important aspects of Idaho Power's resources to meet system energy needs and are reviewed with each IRP. Idaho Power successfully operated all three of its demand response programs in 2022. The total demand response capacity from the company's programs was calculated to be approximately 312 megawatts (MW) with an actual max load reduction of 200 MW.

Total expenditures from all funding sources of demand-side management (DSM) activities were $43 million in 2022—$31.7 million from the Idaho Rider, $10 million from Idaho Power base rates, and $1.3 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).

In addition to the education customers get through participation in specific incentive programs for energy efficiency, Idaho Power educates customers on energy efficiency in many other ways. One of these methods is to produce an annual *Energy Efficiency Guide* with information on energy efficiency equipment and ways to use energy wisely. The 2022 guide was distributed in June, primarily as an insert in the *Boise Weekly* and 24 local newspapers. In 2022, Idaho Power's education and outreach energy advisors (EOEA) delivered nearly 670 presentations with energy-savings messages to audiences of all ages.


**Figure 1. Example graphic from the *2022 Energy Efficiency Guide***

In 2022, the Integrated Design Lab (IDL) conducted 14 technical training lunches. A total of 100 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; 69 new tools were added in 2022.

Idaho Power continued to provide training to its commercial and industrial customers in 2022, delivering the equivalent of six full days of technical training to over 150 individuals.

Idaho Power provided three virtual irrigation workshops for the Irrigation Efficiency Rewards and Irrigation Peak Rewards programs and provided one in-person workshop in Oregon. In October, program staff attended the first annual Idaho Farm and Ranch Conference in Boise and hosted a booth.

The company sponsors significant customer educational outreach and awareness activities promoting energy efficiency, and focuses marketing efforts on saving energy—none of which are quantified or claimed as part of Idaho Power's annual DSM savings, but are likely to result in energy savings that accrue to Idaho Power's electrical system over time.

This *Demand-Side Management 2022 Annual Report* provides a review of the company's DSM activities and finances throughout 2022 and 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 has been locally operated since 1916 and serves more than 610,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon. 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; collectively, the implementation, operation, tracking, and evaluation of these programs and offerings is called demand-side management (DSM).

Results of independent surveys show Idaho Power's efforts to educate and inform customers are successful: the company remains one of the top-ranked utilities for energy efficiency awareness and ranked #3 in the West Midsize Segment of the *J.D. Power 2022 Electric Utility Residential Customer Satisfaction Study*.


**Figure 2. Idaho Power service area map**

## Programs and Offerings

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 usage. DSM programs and offerings by customer sector (residential, commercial/industrial [C&I], and irrigation) are shown in Table 1.

**Table 1. DSM programs by sector, operational type, and location, 2022**

| 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 |
| 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 | Energy Efficiency | ID |
| Home Energy Report 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 Program | Energy Efficiency | ID |
| Shade Tree Project | Energy Efficiency | ID |
| 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 |

## Funding Sources

Energy efficiency and demand response funding comes from multiple sources: Idaho Power base rates, the Idaho and Oregon Energy Efficiency Riders (Riders), and the annual power cost adjustment (PCA) in Idaho. Idaho incentives for the company's demand response programs are recovered through base rates and tracked through 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 $43 million in 2022, as shown in Figure 3.

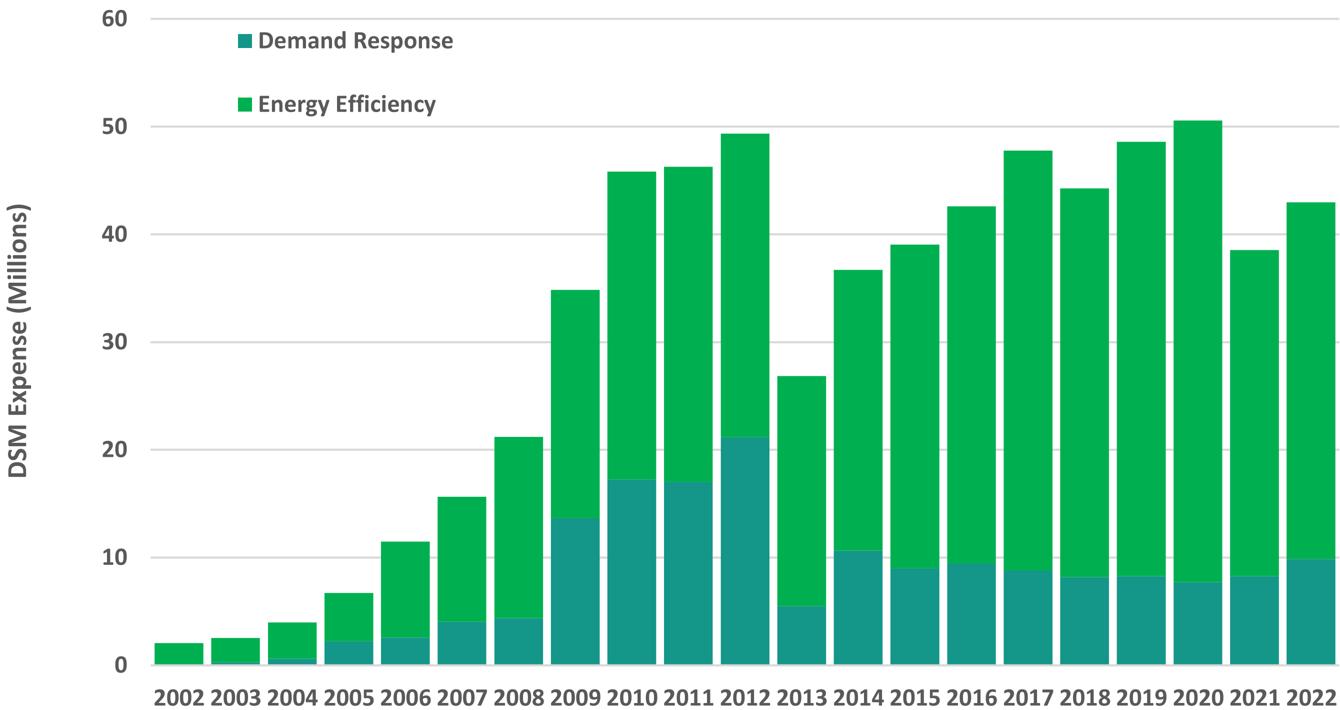



**Figure 3.** **DSM expense history by program type, 2002–2022 (millions [$])**

## Cost-Effectiveness Goals

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of the 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 strives for all programs to have benefit/cost (B/C) ratios greater than one for the utility cost test (UCT), total resource cost (TRC) test, and participant cost test (PCT) at the program and measure levels, where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test adds value when evaluating overall program performance. In 2020, Idaho Power transitioned to using the UCT as the primary cost-effectiveness test for energy efficiency resource planning as directed by the Idaho Public Utilities Commission (IPUC) in Order No. 34503. The company plans to continue to calculate the TRC and PCT because each perspective can help inform the company and stakeholders about the effectiveness of a particular program or measure. Additionally, programs and measures offered in Oregon must use the TRC 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 several factors, such as participation levels or the participants' locations. For instance, heat pumps installed in the Boise area will have lower savings than those 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 not cost-effective, Idaho Power works with its Energy Efficiency Advisory Group (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 the OPUC.

As a result of IPUC Order No. 35336 (IPC-E-21-32) and the Public Utility Commission of Oregon's (OPUC) approval on February 8, 2022 in Docket No. ADV 1355, Idaho Power determines cost-effectiveness for its demand response programs using financial and alternate resource cost assumptions from each IRP.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

## DSM Annual Report Structure

The *Demand-Side Management 2022 Annual Report* consists of this main document and two supplements. The main document contains the following sections related to 2022 DSM activities:

- **Program Performance** is a summary of total energy savings and program expenses, funding, expenditures, and the overall approach to marketing, surveys, evaluations, and cost-effectiveness.
- **Program Activity—Residential, C&I, and Irrigation** provides sector summaries and individual program details, including marketing efforts, cost-effectiveness analyses, customer satisfaction survey results, and evaluation recommendations and responses.
- **Other Programs and Activities** is an overview of DSM-related programs and activities that can span multiple sectors, including market transformation.
- **Appendices 1 through 4** present data related to payments, funding, and program-level costs and savings.

*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, the evaluation plan, EEAG meeting notes, links to NEEA evaluations, copies of IDL reports, research and survey reports, evaluation reports, and other reports related to DSM activities.

# 2022 DSM PROGRAM PERFORMANCE

A summary of the energy efficiency and demand response program performance metrics is presented in this section and in individual program sections later in this report. Appendices 1 through 4 provide additional details on the funding, expenditures, and savings at the program and sector levels.

## Energy Savings and Program Expenses

### *Efficiency*

Energy efficiency programs are available to all customer segments 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 Home Energy Report (HER) Program primarily focus on behavioral energy savings.

Savings from energy efficiency programs are measured on a kilowatt-hour (kWh) or megawatt-hour (MWh) basis. Programs can supply energy savings throughout the year or at different times, depending on the energy efficiency measure. Idaho Power shapes the energy-savings profile based on how end-use equipment uses energy 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 residential, irrigation, industrial, large-commercial, small business, government, and school customers to promote a wide range of energy-saving projects.

Idaho Power devotes significant resources to maintain and improve its energy efficiency and demand response programs. The 2022 total savings, including savings from the Northwest Energy Efficiency Alliance (NEEA), were 169,889 MWh. 2022 savings increased by 26,968 MWh compared to the 2021 savings of 142,921 MWh—a 19% year-over-year increase— and represent enough energy to power approximately 14,900 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 145,440 MWh in 2022 compared to 126,102 MWh in 2021— a 15% year-over-year increase. Savings and expenses are shown in Figure 4.

The 2022 savings results consisted of 28,525 MWh from the residential sector, 109,960 MWh from the C&I sector, and 6,955 MWh from the irrigation sector. The C&I programs contributed

76% of the direct program savings. See Appendix 3 for a complete list of programs and sector-level savings.

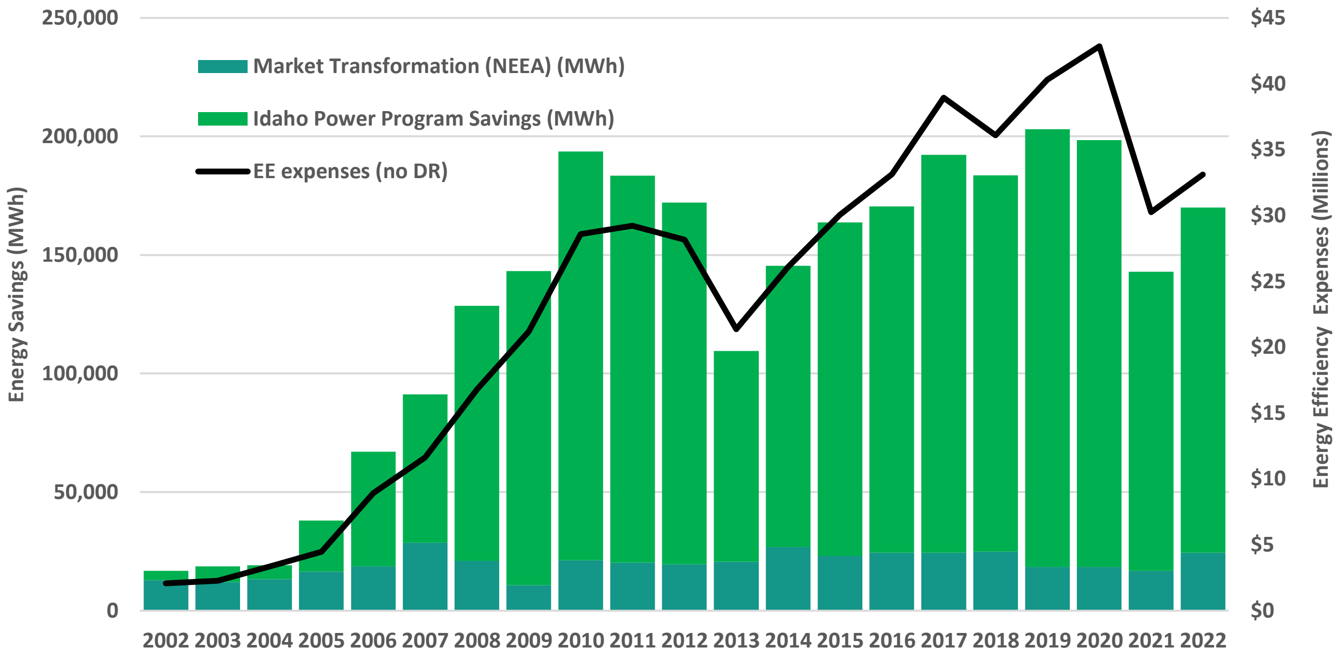



**Figure 4. Annual energy savings and energy efficiency program expenses, 2002–2022 (MWh and millions [$])**

## *Demand Response*

Idaho Power started its modern demand response programs in 2002 and currently has a capacity of more than 8% of its all-time system peak load available to respond to a system 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 is measured both by the actual demand reduction in megawatts (MW) achieved during events, as well as the potential demand reduction if all programs were used at full capacity.

In summer 2022, Idaho Power utilized all or portions of the programs on 15 different days between June 15 and September 15. The 2022 actual maximum non-coincidental load reduction from all three programs was 200 MW (Figure 5). The total capacity for all three programs was approximately 312 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 actual non-coincidental load reduction (200 MW) is calculated using interval meter data from participants. The maximum capacity (312 MW) is calculated using the total enrolled MW from participants with an expected maximum realization rate for those participants. 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 the maximum per-unit reduction ever achieved.

The 2022 demand response season was the first to incorporate program modifications approved by the IPUC in Order No. 35336 (IPC-E-21-32) and approved by the OPUC on February 8, 2022, in Docket No. ADV 1355, which replaced the Settlement Agreement set in IPUC Order No. 32923 and OPUC Order No. 13-482, respectively. The program modifications included several operational and incentive changes that allow the demand response programs to better meet the needs of the overall system. Namely, under the new terms, the end of the demand response season was extended from August 15 to September 15 and events may now extend to later in the evening. The orders also approved higher incentive levels to compensate participants for the extended event windows as well as expand the company's ability to market the programs to all potential customers.

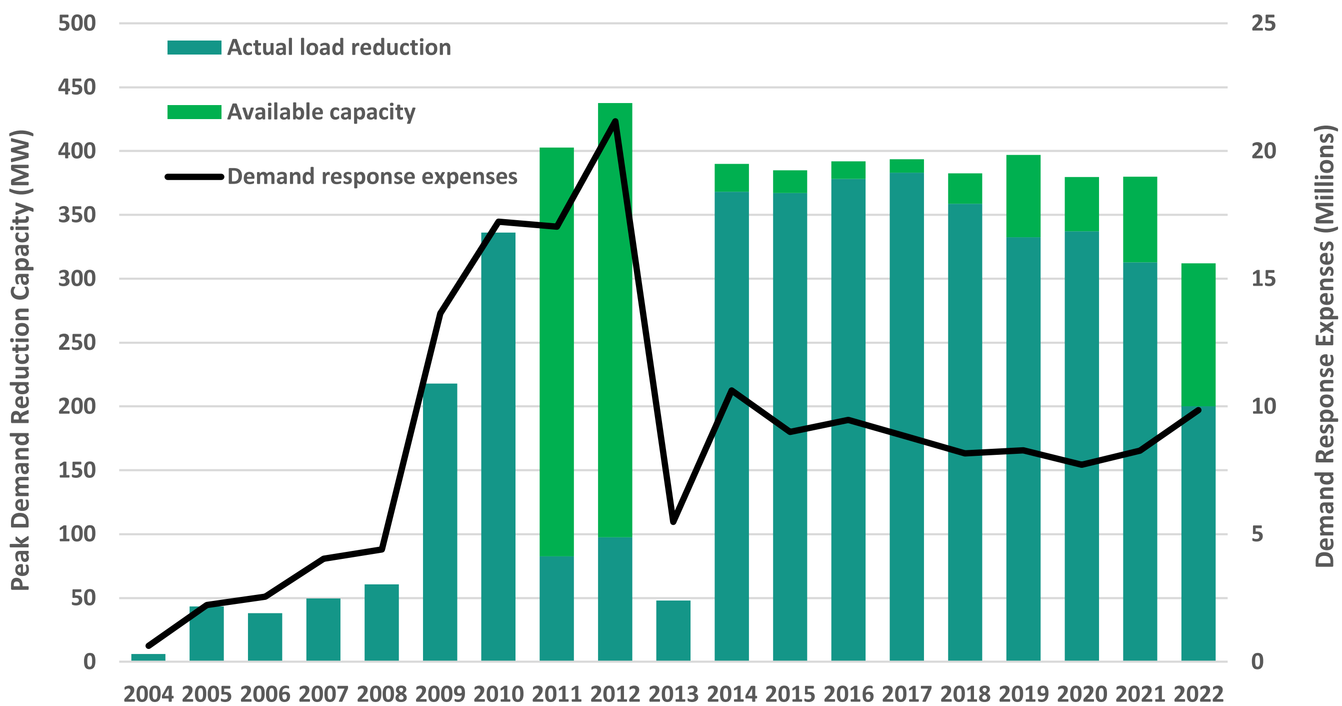



**Figure 5. Peak demand reduction capacity and demand response expenses, 2004–2022 (MW and millions [$])**

**Table 2. DSM programs by sector summary and energy usage/savings/demand reduction, 2022**

| | Program Impacts [a] | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (MWh) | Peak-Load Reduction (MW)[b] | Sector Total (GWh)[c] | Percentage of Energy Usage | Year-End Number of Customers |
| Residential | $ 5,690,839 | 28,525 | | 6,022 | 38% | 518,490 |
| Commercial/Industrial | 17,939,548 | 109,960 | | 7,807 | 49% | 77,431 |
| Irrigation | 2,080,027 | 6,955 | | 1,950 | 12% | 22,071 |
| Market Transformation | 2,789,937 | 24,448 | | | | |
| Demand Response | 9,852,529 | n/a | 200/312 | | | |
| Direct Overhead/Other Programs | 3,103,553 | n/a | | | | |
| Indirect Program Expenses | 1,507,146 | | | | | |
| **Total** | **$ 42,963,579** | **169,889** | **200/312** | **15,779** | **100%** | **617,992** |

[a] Data are rounded to the nearest whole unit, which may result in minor rounding differences.
[b] Maximum actual reduction/maximum potential reduction. Includes 9.7% peak line loss assumptions.
[c] GWh=Gigawatt-hour

## DSM Funding and Expenditures

Funding for DSM programs comes from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. The 2022 Idaho Rider was 3.1% of base rate revenues, pursuant to IPUC Order No. 34871. The 2022 Oregon Rider was 4% of base rate revenues. Additionally, Idaho demand response program incentives were funded through base rates and are tracked through the annual PCA mechanism. DSM expenses not funded through the riders are included in Idaho Power's ongoing operation and maintenance (O&M) costs.

Table 3 shows the total expenditures funded by the Idaho and Oregon Riders and Idaho Power base rates resulting in total DSM expenditures of $42,963,579. 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 3. 2022 funding source and energy savings**

| Funding Source | Expenses [a] | MWh Savings |
|---|---|---|
| Idaho Rider | $ 31,673,550 | 166,233 |
| Oregon Rider | 1,285,478 | 3,360 |
| Idaho Power Base Rates | 10,004,551 | 295 |
| **Total** | **$ 42,963,579** | **169,889** |

[a] Dollars are rounded to the nearest whole unit, which may result in minor rounding differences.

Table 4 and Figure 6 present 2022 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, other categories include items or services that directly benefited customers. The expenses in the Materials & Equipment category were primarily for various kit programs ($930,698) and direct-install weatherization measures

($125,000). Most expenses in the Other Expense category were for marketing ($1,307,293), Custom Projects energy audits ($321,686), program evaluations ($290,983), program trainings ($88,151), and program expenses ($20,466). The Purchased Services category includes payments made to NEEA ($2,789,937), WAQC CAP agencies ($1,212,534), and third-party contractors who help deliver Idaho Power's programs.

**Table 4. 2022 DSM program expenditures by category**

| Program Expenditure Category | | Total [a] | % of Total |
|---|---|---|---|
| Incentive Expense | $ | 25,672,977 | 59.8% |
| Labor/Administrative Expense | | 4,021,552 | 9.4% |
| Materials & Equipment | | 1,097,458 | 2.6% |
| Other Expense | | 2,042,340 | 4.8% |
| Purchased Services | | 10,129,252 | 23.6% |
| **Total** | **$** | **42,963,579** | **100%** |

[a] Dollars are rounded to the nearest whole unit, which may result in minor rounding differences.

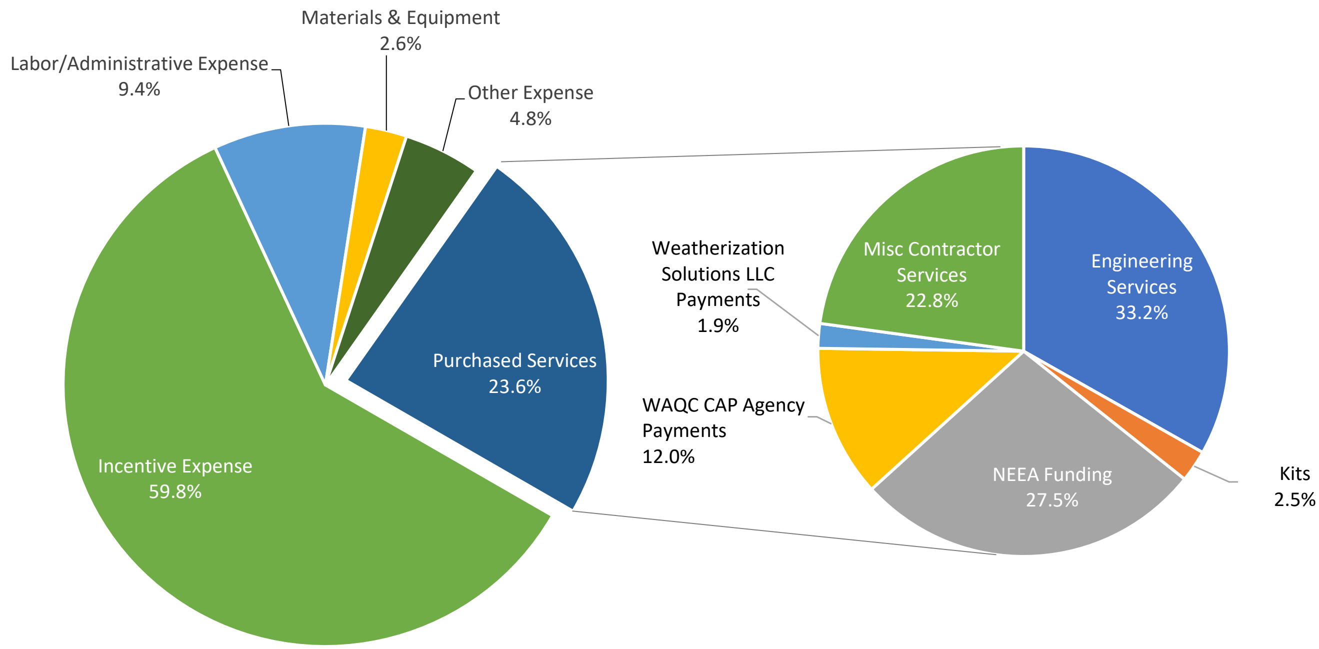



**Figure 6. 2022 DSM program expenditures by category**

**Table 5. 2022 DSM program incentive totals by program type and sector**

| Program Type—Sector [a, b] | | Total [c] | % of Total |
|---|---|---|---|
| DR—Residential | $ | 379,634 | 1.5% |
| DR—Commercial/Industrial | | 430,322 | 1.7% |
| DR—Irrigation | | 7,895,971 | 30.8% |
| EE—Residential | | 1,836,424 | 7.2% |
| EE—Commercial/Industrial | | 13,461,084 | 52.4% |
| EE—Irrigation | | 1,669,543 | 6.5% |
| **Total** | **$** | **25,672,977** | **100%** |

[a] DR = demand response
[b] EE = energy efficiency
[c] Dollars are rounded to the nearest whole unit, which may result in minor rounding differences.

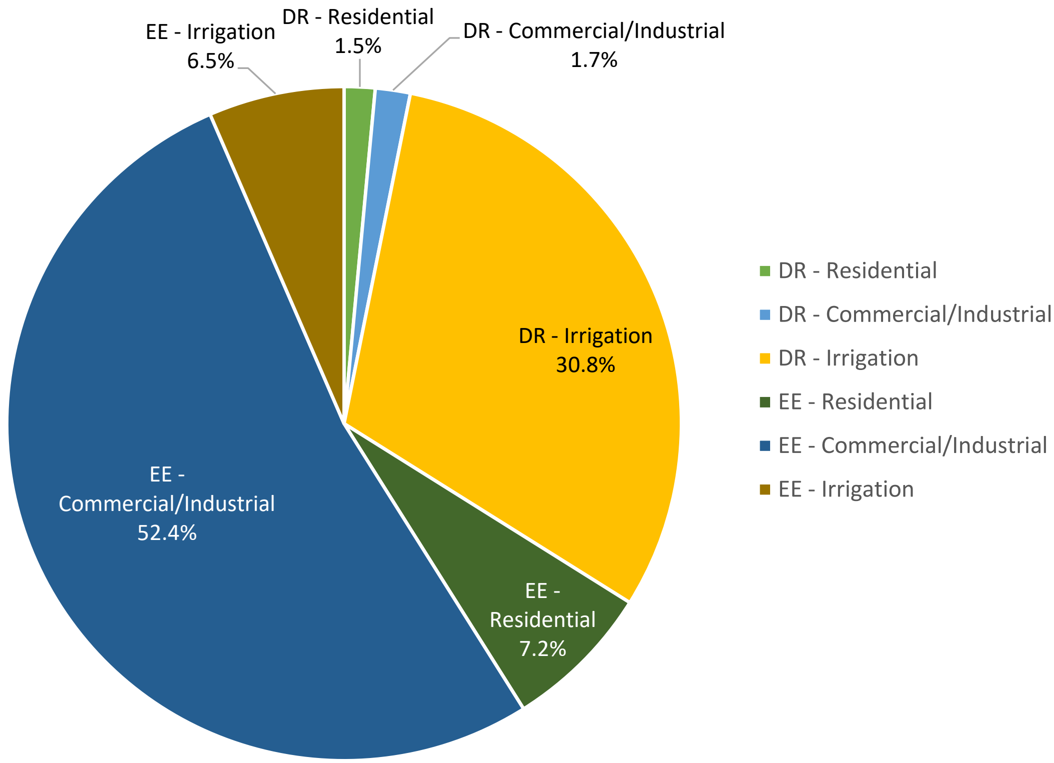



**Figure 7. Percent of DSM program incentive expenses by program type and sector, 2022**

## Customer Education

Idaho Power produced an *Energy Efficiency Guide* in 2022 and distributed it in June, primarily as an insert in the *Boise Weekly* and 24 local newspapers. As COVID-19 concerns declined, Idaho Power was able to re-engage with customers in person to discuss energy efficiency at 42 community events. Idaho Power also distributed 1,550 copies of the *30 Simple Things You Can Do to Save Energy* booklet directly to customers. In 2022, Idaho Power's program specialists and education and outreach energy advisors (EOEA) delivered nearly 670 presentations and trainings with energy savings messages to audiences of all ages.

Efforts to enhance digital communication continued—with the goal of bringing a variety of energy and money-saving tips to a broad range of customers.

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 2022, the IDL conducted 14 in-person technical training sessions with 100 architects, engineers, designers, project managers, and other interested parties. Also, IDL hosted six virtual Building Simulation Users Group (BSUG) sessions with 195 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 and 69 new tools were added in 2022. In 2022, the ERL home page had 2,768 visitors.

Over the course of 11 days in 2022, Idaho Power delivered six equivalent full-time days of live, online, technical training sessions at no cost to the customers. Topics included the following:

- HVAC System Testing for Energy Efficiency
- Motors and Variable Frequency Drives (VFD)
- Fan System Training
- Chilled Water System and Cooling Towers
- Compressed Air Training

The level of participation in 2022 remained high, with 216 individuals signing up for the sessions and 150 unique logins. Due to the virtual nature of the course, in some cases there were multiple attendees at a single login location.

Idaho Power offered four live, online, technical training sessions to industrial wastewater customers that were attended by 50 participants. Topics included the following:

- Water Energy Basics
- Wastewater Typical No-/Low-Cost Opportunities
- Pumps and Efficiency
- Activated Sludge Basics

Aside from the classes listed above, Idaho Power also partnered with the Northwest Energy Efficiency Council (NEEC) to administer a Building Operator Certification Level I Course which began in November 2021 and was completed in May 2022. Idaho Power sponsored 17 customers who signed up for the training by paying $900 of the $1,895 tuition cost.

Idaho Power provided three virtual irrigation workshops for the Irrigation Efficiency Rewards and Irrigation Peak Rewards programs and provided one in-person workshop in Oregon. In

October, program staff attended the first annual Idaho Farm and Ranch Conference in Boise and hosted a booth.

## Marketing

Idaho Power used multi-channel marketing and public relations (PR) strategies in 2022 to improve communication and increase energy efficiency program awareness among its customers. The company employs a wide variety of media and marketing, including 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's marketing staff networks with organizations across the region and industry to track 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 learn what works in other regions, Idaho Power staff virtually attended several conferences and webinars in 2022, 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 25% of the company's total social media content promoted energy efficiency in 2022. Idaho Power regularly posted content encouraging energy efficiency behaviors, program enrollment, and customer engagement on Facebook, Twitter, YouTube, and LinkedIn. Social media content also showcased local businesses and organizations that have benefitted from Idaho Power energy efficiency efforts. Idaho Power engaged with customers who posted their own social media content about Idaho Power programs. Idaho Power's Facebook and Twitter pages hosted two customer sweepstakes giveaways, encouraging customers to enter by leaving a comment about how they save energy in the summer or winter.

Facebook, Twitter, and LinkedIn all remain as priority channels for engaging and communicating directly with customers on energy efficiency tips and program offerings.

At the end of 2022, Idaho Power had approximately 25,100 followers on Facebook, 6,950 on Twitter, 14,345 on LinkedIn, and 3,000 on Instagram.

### *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 2022, the company's energy efficiency homepage received 10,235 page views, the residential landing page received 98,014 views, and the business and irrigation landing pages received 21,243 views. 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: videos telling energy efficiency success stories; *Connections*, a 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; and public events, such as incentive check presentations.

In 2022, the January and June issues of *Connections* were devoted to energy efficiency, with additional energy efficiency content for small business customers in the February issue. The January issue included a variety of ideas for energy-saving tips, such as efficient thermostat settings, the benefits of induction cooking, and knowing when to replace home appliances for more efficient options. The June edition featured a residential customer energy-saving success story, including information on how a local couple saves energy in the summer, as well as information about how summer temperatures impact energy use, low-cost energy efficiency improvement, and using My Account to control your energy use.

With another hot summer throughout the company's service area, energy efficiency information for staying cool during high temperatures was once again shared across the company's owned media channels and with regional media outlets. Social media messaging included tips about how to save energy during the high demand hours from 4 to 9 p.m.

To recognize National Dairy Month in June 2022, Idaho Power shared multiple pieces of content through social media, *News Briefs,* and videos, with a portion of the information focused on energy efficiency. The company produced a new video highlighting local ice cream maker, The STIL, including how energy and energy efficiency factor into their business. The company also produced a short Instagram video highlighting a local dairy farmer who works closely with Idaho Power for their power and energy efficiency needs.

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.

## Customer Relationship Survey

Relationship surveys measure the satisfaction of several aspects of a customer's relationship with Idaho Power, including energy efficiency, at a very high level. As such, the surveys are not intended to measure all aspects of the energy efficiency programs.

The *2022 Burke Customer Relationship Survey* asked two questions related specifically to satisfaction with Idaho Power's energy efficiency programs: 1) Have you participated in an Idaho Power energy efficiency program? 2) Overall, how satisfied are you with the energy efficiency program? In 2022, 20.7% of the survey respondents across all sectors indicated they participated in an Idaho Power energy efficiency program, and 91.7% were "very" or "somewhat" satisfied with the program they participated in.

The sector-level results of the annual 2022 survey are discussed in the Residential, C&I, and Irrigation Sector Overview sections of this report.

## Customer Satisfaction Surveys

To ensure meaningful survey results, Idaho Power conducts program research every two to three years unless programs have been changed significantly. Throughout 2022, 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*.

## Evaluations

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 bidding 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 the evaluations and research to continuously refine its DSM programs.

In 2022, Idaho Power contracted third-party evaluators to conduct program evaluations for the following programs: HER Program (impact evaluation), C&I New Construction (impact and process evaluation), C&I Retrofits (impact and process evaluation), and Commercial Energy-Saving Kits (Commercial ESK) (impact and process evaluation).

External program administrators compiled program summary reports for the Student Energy Efficiency Kits (SEEK) program and the HER program, and the company conducted internal analyses for the A/C Cool Credit, Flex Peak, and Irrigation Peak Rewards programs.

To support Idaho Power's long-term planning through the IRP, both an Energy Efficiency Potential Study and Demand Response Potential Study were completed in 2022. Idaho Power engaged a third party, and utilizing Idaho Power's customer data and industry information, a 20-year forecast of energy efficiency savings and megawatts of program potential for demand response was estimated. The information from these studies is being used in the 2023 IRP.

A summary of the results of these evaluations is available in the respective program sections. An evaluation schedule and the final reports from evaluations, studies, and research completed in 2022 are provided in *Supplement 2: Evaluation*.

## Cost-Effectiveness Results

A summary of the cost-effectiveness metrics calculated for the energy efficiency programs in 2022 is provided in Table 6. Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

**Table 6. Cost-effectiveness summary by energy efficiency program**

| Program/Sector | UCT | TRC | Ratepayer Impact Measure (RIM) | PCT |
|---|---|---|---|---|
| Educational Distributions | 1.31 | 1.62 | 0.38 | n/a |
| Energy Efficient Lighting | 1.68 | 1.52 | 0.41 | 4.35 |
| Energy House Calls[1] | 0.70 | 0.77 | 0.27 | n/a |
| Heating & Cooling Efficiency Program | 0.98 | 0.30 | 0.34 | 0.76 |
| Home Energy Report Program[2] | 0.71 | 0.79 | 0.25 | n/a |
| Multifamily Energy Savings Program[3] | 0.49 | 0.68 | 0.25 | n/a |
| Rebate Advantage | 1.18 | 0.54 | 0.34 | 1.56 |

| Program/Sector | UCT | TRC | Ratepayer Impact Measure (RIM) | PCT |
|---|---|---|---|---|
| Residential New Construction Program | 1.45 | 0.84 | 0.41 | 1.70 |
| Shade Tree Project | 1.02 | 1.21 | 0.47 | n/a |
| Weatherization Assistance for Qualified Customers | 0.17 | 0.32 | 0.13 | n/a |
| Weatherization Solutions for Eligible Customers | 0.15 | 0.23 | 0.11 | n/a |
| **Residential Energy Efficiency Sector**[4] | **1.00** | **0.76** | **0.34** | **2.89** |
| Commercial and Industrial Energy Efficiency Program | | | | |
| Custom Projects | 2.88 | 1.12 | 0.88 | 1.17 |
| New Construction | 4.25 | 3.64 | 0.68 | 5.41 |
| Retrofits | 2.01 | 1.11 | 0.57 | 1.61 |
| Commercial Energy-Saving Kits | 0.78 | 0.87 | 0.39 | n/a |
| Small Business Direct Install | 0.95 | 1.50 | 0.43 | n/a |
| **Commercial/Industrial Energy Efficiency Sector**[5] | **2.71** | **1.34** | **0.73** | **1.71** |
| Irrigation Efficiency Rewards | 2.69 | 2.54 | 0.79 | 2.66 |
| **Irrigation Energy Efficiency Sector**[6] | **2.69** | **2.54** | **0.79** | **2.66** |
| **Energy Efficiency Portfolio**[7] | **2.02** | **1.43** | **0.64** | **2.01** |

[1] Program closed June 30, 2022.

[2] Cost-effectiveness based on 2022 savings and expenses. Cost-effectiveness ratios also calculated for the program life-cycle. Program life-cycle UCT and TRC 1.17 and 1.29, respectively.

[3] Program closed December 31, 2022.

[4] Residential sector cost-effectiveness excludes WAQC benefits and costs. If included, the UCT ,TRC, RIM, and PCT would be 0.84, 0.67, 0.32, and 2.56, respectively.

[5] C&I Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors Rewinds.

[6] Irrigation Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors Rewinds.

[7] Portfolio cost-effectiveness excludes WAQC benefits and costs. If included, the UCT, TRC, RIM, and PCT would be 1.94, 1.40, 0.63, and 2.00, respectively.

# 2022 DSM PROGRAM ACTIVITY

## Residential Sector Overview

In 2022, Idaho Power's residential sector consisted of 512,803 customers averaged throughout the year; Idaho customers averaged 498,921 and eastern Oregon averaged 13,882. The average number of residential sector customers grew by 12,716 in 2022, an increase of 2.5% from 2021. The residential sector represented 38.3% of Idaho Power's actual total billed electricity usage and 47.0% of overall retail revenue in 2022.

Table 7 shows a summary of 2022 participants, costs, and savings from the residential energy efficiency programs.

**Table 7. Residential sector program summary, 2022**

| Program | Participants | | Total Cost | | Savings | |
|---|---|---|---|---|---|---|
| | | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW)[1] |
| **Demand Response** | | | | | | |
| A/C Cool Credit | 19,127 | homes | $ 829,771 | $ 829,771 | | 20.1/26.8 |
| **Total** | | | **$ 829,771** | **$ 829,771** | | **20.1/26.8** |
| **Energy Efficiency** | | | | | | |
| Easy Savings: Low-Income Energy Efficiency Education | 267 | HVAC tune-ups | 152,718 | 152,718 | 22,755 | |
| Educational Distributions | 49,136 | kits/giveaways | 1,086,813 | 1,086,813 | 3,741,954 | |
| Energy Efficient Lighting | 370,739 | lightbulbs | 534,982 | 714,445 | 1,728,352 | |
| Energy House Calls | 52 | homes | 38,163 | 38,163 | 54,516 | |
| Heating & Cooling Efficiency Program | 1,080 | projects | 666,016 | 2,414,026 | 1,310,260 | |
| Home Energy Audit | 425 | audits | 184,858 | 239,783 | 28,350 | |
| Home Energy Report Program | 104,826 | treatment size | 964,791 | 964,791 | 20,643,379 | |
| Multifamily Energy Savings Program | 97 [3] | units [buildings] | 34,181 | 34,181 | 41,959 | |
| Oregon Residential Weatherization | 7 | audits/projects | 8,825 | 8,825 | 0 | |
| Rebate Advantage | 97 | homes | 167,622 | 402,649 | 255,541 | |
| Residential New Construction Program | 109 | homes | 235,732 | 578,922 | 337,562 | |
| Shade Tree Project | 1,874 | trees | 128,856 | 128,856 | 39,595 | |
| Weatherization Assistance for Qualified Customers | 147 | homes/non-profits | 1,281,495 | 2,028,513 | 272,647 | |
| Weatherization Solutions for Eligible Customers | 27 | homes | 205,788 | 205,788 | 48,233 | |
| **Total** | | | **$ 5,690,839** | **$ 8,998,473** | **28,525,103** | |

**Notes:**

See Appendix 3 for notes on methodology and column definitions.

Totals may not add up due to rounding.

[1] Demand response program reductions are reported with 9.7% peak loss assumption. Maximum actual demand reduction/maximum demand capacity.

### Residential DSM Programs

**A/C Cool Credit.** A demand response program that gives residential customers a credit for allowing Idaho Power to cycle their air conditioning (A/C) units during periods of high energy demand or for other system needs.

**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, including giving away various efficient products and engaging elementary students with in-class and at-home activities.

**Energy Efficient Lighting.** The Energy Efficient Lighting program provides incentives directly to manufacturers or retailers, so that discounted prices are passed on to the customer at the point of purchase.

**Energy House Calls.** A program designed specifically for owners of manufactured homes to test and seal ducting and offer energy-efficient products designed to reduce energy costs.

**Heating & 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.** Idaho customers living in multifamily homes with discrete meters or single-family homes pay a reduced price for an energy audit to identify energy efficiency improvement opportunities. Participants may receive energy-efficient products for no additional cost.

**Home Energy Report Program.** A program that sends Idaho customers energy reports to help them understand their energy use and provides energy efficiency tips and incentive information.

**Multifamily Energy Savings Program.** A program offering renters in multifamily 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 for 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.

**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.

## *Marketing*

Idaho Power ran a multi-faceted advertising campaign in the spring (May and June) 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 ads, digital ads, sponsorships, Facebook ads, and boosted posts aimed at a variety of customer demographics across the service area. New in 2022, the company added podcast advertising, college sports sponsorships, and two new seasonally relevant contests: Smart Summer Savings Giveaway and Kitchen Gadgets Galore Winter 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 2022. The company emails only 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, seasonal energy efficiency tips, and various program promotions. Detailed information can be found in respective program sections.

### Digital

During the spring campaign, web users were exposed to 4,410,758 display ads (animated GIF 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 4,009 times, resulting in a click-through rate of 0.09%. In the fall, the display ads received 4,904,771 impressions and 4,925 clicks, resulting in a click-through rate of 0.08%.

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 530,211 impressions and 54,374 clicks throughout the year.

### Podcasts

New in 2022, Idaho Power added podcast advertising to the media mix: 30-second Idaho Power audio ads, called “dynamic ads,” were inserted into a listener’s podcast if they resided in the company’s service area. The ads targeted customers by the type of listener rather than being run on a specific show. Types of shows that featured Idaho Power ads appealed to listeners, such as green-living enthusiasts, customers interested in home improvement/home repair, and homeowners age 18 and over. The ads received 521,803 impressions in spring. Fall podcast ads garnered 390,787 impressions.

### Television

Idaho Power used network television and Hulu advertising for the spring and fall campaigns. 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, Apple TVs, or Amazon Fire TVs. The network television campaigns focused on primetime and news programming that reaches the highest percentage of the target market, adults aged 25 to 64.

During the spring campaign, an ad ran 816 times in the Boise, Pocatello, and Twin Falls media markets on network television. The ad reached 30% of the Boise area target audience, 48% of the Twin Falls area target audience, and 60% of the Pocatello area target audience. The target audience saw the ad 16.5 times in Boise, 16.6 times in Twin Falls, and 17.5 times in Pocatello. Hulu spring ads delivered 690,171 impressions with a 97.8% completion rate. OTT ads delivered 425,539 impressions with a 97.91% video completion rate. The spring campaign also used Spanish network television ads: the Boise target audience saw 147 paid spots, and the Pocatello market saw 49 spots. Spanish TV ads ran during the fall campaign as well; the Boise target audience saw 86 paid spots, and the Pocatello audience saw 150 spots. Ad reach and frequency information are not available for Spanish stations.

During the fall campaign, the TV spot ran 531 times in the Boise, Pocatello, and Twin Falls media markets. The ads reached 30% of the Boise target audience, 43% of the Twin Falls target audience, and 60% of the Pocatello target audience. The target audience saw the ad 4.5 times in Boise, 5.4 times in Twin Falls, and 5 times in Pocatello. Hulu ads received 699,807 completions. OTT ads delivered 536,610 impressions with a 97.5% video completion rate.

Idaho Power also sponsored commercials on Idaho Public Television in the Boise and Pocatello markets that ran a total of 56 times in the spring and 65 times in the fall.

In 2021, the television station began charging for each energy efficiency television segment. Idaho Power paid for three segments in 2022 with topics that included energy-efficient spring and fall tips and ways to beat the summer heat.

### Radio

As part of its spring and fall campaigns, Idaho Power ran 30-second radio spots on major commercial radio stations in the service area. To obtain optimal reach, the spots ran on several station formats, including classic rock, news/talk, country, adult alternative, rock, sports, and classic hits. The message was targeted toward adults ages 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 areas. During the spring campaign, Idaho Power ran 2,456 English radio spots. These spots reached 46% of the target audience in Boise, 67% in Pocatello, and 66% in Twin Falls. The target audience was exposed to the ad 7.6 times in Boise, 9.7 times in Pocatello, and 8.8 times in Twin Falls. During the fall campaign, the company ran 2,246 English radio spots. These spots reached 39.7% of the target audience in Boise, 57.8% of the target audience in Pocatello, and 65.6% of the target audience in Twin Falls. The target audience was exposed to the message 7.6 times in Boise, 8.6 times in Pocatello, and 9.6 times in Twin Falls during the fall campaign.

In spring, Idaho Power also ran 419 ads on Spanish-speaking radio stations and 294 National Public Radio (NPR) ads in the service area targeting adults ages 25 to 54. The fall campaign included 372 Spanish ads and 317 NPR ads.

Idaho Power ran 30-second spots with accompanying visual banner ads on Pandora internet radio, which mobile and web-based devices access. In the spring, records show 697,749 impressions and 89 clicks to the Idaho Power residential energy efficiency web page. The fall ads yielded 692,623 impressions and 45 clicks. Ads also ran on Spotify internet radio and yielded 288,504 impressions and 195 clicks in the spring and 374,041 impressions with 129 clicks in the fall.

### 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, *Idaho Magazine*, *Boise Lifestyle* and *Meridian Lifestyle* magazines, and *IdaHome Magazine.* The spring ads highlighted individual energy efficiency tips, such as using the power-save setting on electronics and running ceiling fans counterclockwise for summer. The fall ads featured tips on minimizing gadgets (use one at a time) and using smart power strips.

In 2022, 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 2023 Welcome Kits. The previous edition of the guide was included in

2021 Welcome Kits, provided to WAQC customers, and shared with customers who attended events Idaho Power participated in before the COVID-19 restrictions.

### Social Media

Three Facebook ads for the 2022 energy efficiency campaign received 90,664 impressions and 909 clicks per ad.

Throughout the year, Idaho Power used Facebook and Twitter posts and boosted Facebook posts for various programs and easy energy efficiency tips for customers to implement at home and at work.

### Out-of-Home

In 2022, Idaho Power participated in several 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 helped maintain energy efficiency program awareness throughout the year. Tactics included a full-side bus wrap on a Pocatello Regional Transit bus in Eastern Idaho.

Idaho Power sponsored the Boise Hawks (minor league baseball team) from May through September. As part of the sponsorship package, Idaho Power received a 15-second digital ad on the four screens within the stadium. The company's energy efficiency ad was shown a total of 13,589 times during the 48-game season and the overall season attendance was 160,582. Boise Hawks use a special TV system called In-Stadium Media (ISM), which can tell how often spectators look at screens. The average interaction/engagement rate was 52%, which is above the industry standard of 42%. Two 15-second Idaho Power commercials were also shown during the Boise Hawks Facebook Live Broadcast for all games.

A Boise State University (BSU) sponsorship was also part of the marketing strategy in 2022. Energy efficiency messaging was featured at Albertsons Stadium during football games and included digital concourse signage, a game co-sponsorship and table, logo recognition on the digital game program cover, and the Idaho Power logo included on promotional materials leading up to the game. The BSU basketball sponsorship included a 30-second digital ribbon board that rotated throughout the game.

Sponsoring sporting events at Idaho State University (ISU) was also part of the marketing plan. The sponsorship included two permanent banners located in each end zone of Holt Arena, which has an annual attendance of over 500,000. Idaho Power was also recognized during each home football game by being the presenting sponsor of the "Idaho Power Helmet Shuffle Game" shown on the big screen. ISU basketball games featured an Idaho Power animated graphic (for two minutes of each game) featured on the LED courtside board.

Idaho Power used weather-triggered billboards in Boise, Pocatello, Nampa, and Caldwell. These are electronic billboards operating in January and July with variable messaging based on the outside temperatures. This tactic keeps energy efficiency top-of-mind and demonstrates simple ways customers can reduce energy use during extreme weather.

Idaho Power also used static billboards to reach customers in rural areas. A Spanish billboard was placed in Kimberly (near Twin Falls) and an English billboard was placed in Heyburn (by Burley).

### Public Relations

Many of the company's PR activities focused on the residential sector. Energy-saving tips in *News Briefs*, TV segments, news releases, and *Connections* newsletter articles aim to promote incentive programs and/or educate customers about behavioral or product changes they can make to save energy in their homes.

See the Program Performance section and the C&I Sector Overview for more 2022 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 2,000 actively engaged members from across Idaho Power's service area. Idaho Power typically sends these members between six and 12 surveys per year. In 2022, Idaho Power included ten energy efficiency messages with survey invitations resulting in nearly 13,500 touchpoints.

Recruitment for the Empowered Community is conducted annually to refresh the membership. Throughout February and March 2022, various types of recruitment were conducted with residential customers, including messages on paperless billing emails, a *News Brief* to local media outlets, pop-up ads on My Account, direct emails, and social media posts. In 2022, 1,017 new members were added to Empowered Community.

### Seasonal Sweepstakes

In 2022, Idaho Power ran two seasonally focused energy efficiency sweepstakes—the Smart Summer Savings Summer Giveaway in August and the Kitchen Gadgets Galore Giveaway in December. Both sweepstakes aimed to maintain awareness about energy efficiency and the impact a small change can make.

The summer sweepstakes ran August 15 through 24 and received 2,774 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 one of 10 smart thermostats. The sweepstakes was promoted with email messaging to 287,449 customers, and social media posts reached 9,108 customers, receiving 697 engagements (likes, comments, shares). The sweepstakes was also promoted on idahopower.com through a pop-up ad on the My Account homepage.

The winter sweepstakes ran December 2 through 16 and received 10,428 entries. Customers were asked to comment—through social media or on the Idaho Power website—with a way they saved energy in the cold winter months. In return, participants were entered to win one of five kitchen gadget bundles that included an air fryer, pressure cooker, electric tea kettle and smart coffee pot. The sweepstakes was promoted with email messaging to 307,431 customers and paid social media posts reached 1,300 customers, receiving 424 post engagements. The sweepstakes was also promoted through a pop-up ad on the company's My Account homepage. It was featured in *News Briefs* to media outlets and was promoted on idahopower.com.

### *Customer Satisfaction*

Idaho Power conducts the *Burke Customer Relationship Survey* each year. In 2022, on a scale of zero to 10, residential survey respondents rated Idaho Power 7.88 regarding offering programs to help customers save energy, and 7.80 related to providing customers with information on how to save energy and money.

Twenty-one percent of residential 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, 93% were "very" or "somewhat" satisfied with the program.

Idaho Power customer awareness of energy efficiency programs is among the highest in the nation: 65.2% of the residential respondents in the *J.D. Power and Associates 2022 Electric Utility Residential Customer Satisfaction 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 were unaware of the programs. Idaho Power ranked third out of 17 utilities included in the West Midsize Segment of this study.

See the individual program sections for program-specific customer satisfaction survey results.

### *Field Staff Activities*

In 2022, Idaho Power's residential and commercial energy advisors and EOEAs continued connecting with customers through in-person meetings, presentations, and events to promote energy efficiency programs and offerings. More than 90% of these interactions were in person. The year also saw a return of the large legacy events including home and garden shows, as well as career, STEM, and science fairs. Energy advisors dedicated a larger percentage of their time to presentations and events at secondary schools, colleges, universities, and trade schools, as well as civic and community audiences.

Idaho Power continued to focus on the training and development of its energy advisors to expand their knowledge, skills, and abilities related to energy efficiency programs, new technologies, and serving customers. One of the highlights during the year was an offering of a residential building science class by an external trainer who shared insights and perspectives about windows, insulation, building envelope, appliances, HVAC, and other residential measures. Idaho Power also held specific training classes on lighting, building envelope, HVAC, pumps, motors, and refrigeration.

## A/C Cool Credit

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 19,127 | 20,995 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW)* | 20.1/26.8 | 26.7/29.4 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $429,722 | $420,376 |
| | Oregon Energy Efficiency Rider | $24,491 | $25,366 |
| | Idaho Power Funds | $375,558 | $306,247 |
| | Total Program Costs—All Sources | $829,771 | $751,989 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/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 |

*Maximum actual demand reduction/maximum potential demand reduction. Demand response program reductions are reported with 9.7% peak loss assumptions.

### 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 periods of high energy demand or for other system needs.

Customers' A/C units are controlled using switches that communicate by powerline carrier (PLC) using the same system used by Idaho Power's advanced metering infrastructure (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 is 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 September 15 (excluding weekends and holidays)
- Up to four hours per day
- A maximum of 16 hours per week and 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 2022, a new tariff was filed and approved to update the cycling season guidelines so the program could run from June 15 to September 15. Before the updates, the cycling season ran from June 15 to August 15. The extended cycling season proved beneficial when there were higher than average temperatures during the first half of September, which resulted in events being called on three days that wouldn't have been available prior to the change.

In 2022, 19,127 customers participated in the program, with 217 in Oregon and 18,910 in Idaho. Thirteen cycling events occurred, and all were successfully deployed. Table 8 shows each event with the cycling percentage, the maximum temperature during the event, and the maximum load reduction. The cycling rate was 55% for five of the events and 50% for the remaining eight events, and the communication level exceeded 90% for each event.
Idaho Power calculated the maximum potential capacity in 2022 to be 26.8 MW at the generation level. This estimate of the program capacity is based on the maximum per-unit reduction ever achieved at the generation level of 1.4 kilowatt (kW) per participant.
Customers receive a $5.00 incentive for each month of participation between June 15 and September 15, resulting in a total annual incentive potential of $20.00. The credits appear on their July through October bill statements.

**Table 8. A/C Cool Credit demand response event details**

| Event Date | Event Time | Cycling Rate | High Temperature | Maximum Load Reduction (MW) |
|---|---|---|---|---|
| July 7 | 6–9 p.m. | 55% | 94°F | 11.4 |
| July 24 | 4–8 p.m. | 50% | 101°F | 16.7 |
| July 28 | 4–8 p.m. | 50% | 103°F | 18.1 |
| July 29 | 4–8 p.m. | 50% | 104°F | 20.1 |
| August 1 | 6–9 p.m. | 55% | 102°F | 18.7 |
| August 8 | 5–8 p.m. | 55% | 102°F | 16.4 |
| August 9 | 5–8 p.m. | 55% | 98°F | 16.8 |
| August 17 | 6–10 p.m. | 50% | 102°F | 14.5 |
| August 31 | 6–10 p.m. | 50% | 105°F | 14.9 |
| September 1 | 5–8 p.m. | 55% | 97°F | 15.7 |

| Event Date | Event Time | Cycling Rate | High Temperature | Maximum Load Reduction (MW) |
|---|---|---|---|---|
| September 2 | 5–9 p.m. | 50% | 100°F | 15.5 |
| September 6 | 5–9 p.m. | 50% | 100°F | 12.9 |
| September 7 | 5–9 p.m. | 50% | 104°F | 17.1 |

Throughout 2022, Idaho Power representatives continued site visits to check switches and equipment to improve communication levels. COVID-19-related safety protocols remained in place, including calling each customer before the visit to explain the process and safety measures and not visiting any site where the customer was uncomfortable with the process. The company will continue work to ensure devices associated with the program are communicating on an ongoing basis.

During the site visits, Idaho Power representatives placed informational stickers on devices that included a safety warning regarding risk of electric shock if the sealed demand response unit were opened, and a toll-free phone number customers could call with questions.

### Marketing Activities

Idaho Power actively marketed the A/C Cool Credit program in 2022.

The company mailed information to existing participants before the start of the 2022 season to describe the program specifics and parameter changes—specifically the extended program season and the additional month to receive an additional $5.00 incentive. A postcard was also sent to participants reminding them of the upcoming season.

In the spring and throughout the summer, the company used postcards, phone calls, direct-mail letters, and home visits (leaving door hangers for those not home) to recruit customers moving into houses with existing switches and previous program participants who moved into new homes without switches. The company also sent recruitment letters to select customers who are homeowners and have not participated previously. In total, 81,391 direct-mail letters were sent. In addition to the letters, follow-up emails (to customers with emails on file) were sent a few weeks after the letter, reminding customers to sign up.

The program was promoted on a KTVB channel 7 segment, where an Idaho Power representative talked with the show host about the benefits of the program. Idaho Power's summer *Energy Efficiency Guide* featured a promotional blurb on the program, encouraging customers to visit the website and sign up.

Participating customers received a thank you and a credit reminder message on their summer bills, and Idaho Power concluded the season by sending a thank-you postcard to participants.

### Cost-Effectiveness

Idaho Power determines cost-effectiveness for its demand response program using the approved method for valuing demand response under IPUC Order No. 35336 and approved by the OPUC on February 8, 2022, in Docket No. ADV 1355. Using financial and alternate resource cost assumptions from the *2021 Integrated Resource Plan*, the defined cost-effective threshold for operating Idaho Power's three demand response programs for the maximum allowable 60 hours is $82.91 per kW under the current program parameters.

The A/C Cool Credit program was dispatched for 13 events (totaling 47 event hours) and achieved a maximum demand reduction of 20.1 MW with a maximum potential capacity of 26.8 MW. The total expense for 2022 was $829,771 and would have remained the same if the program had been fully used for 60 hours because there are no additional variable incentives paid for events called beyond the three minimum required events. Using the total cost and the maximum potential capacity results in a program cost of $30.99 per kW. This is less than the threshold, and therefore, the program was cost-effective.

A complete description of the cost-effectiveness of Idaho Power's demand response programs is included in *Supplement 1: Cost-Effectiveness*.

### Evaluations

In 2021, Idaho Power contracted a third party to conduct an impact evaluation of the A/C Cool Credit Program. Following are the recommendations of the evaluations and Idaho Power's response to each.

*Utilize a mixed model or regression model to estimate saving for the programs*. Idaho Power has adopted the mixed-model approach for calculating load reduction for the program.

*Utilize proxy event days to estimate bias and error when determining which model to select for estimating baseline usage*. Idaho Power has adopted this approach for calculating load reduction for the program.

*The evaluators recommend calling DR events on days with the highest forecasted Cooling Degree Days to maximize program demand reductions*. Idaho Power has updated its program curtailment calculator to incorporate forecasted hourly Cooling Degree Days. This calculator provides system operators an estimate of the demand reduction that can be attained by calling an A/C Cool Credit event that day. However, while potential curtailment is an important metric, the decision to call an event is ultimately based on a wide variety of factors relating to the overall electrical system needs, and not just for the goal of maximizing program load reductions.

In 2022, Idaho Power performed an internal review to evaluate the demand reduction over the course of the 13 event days. The demand reduction was calculated by comparing the actual average load for participating customers on each of the 13 event days to a corresponding baseline. The baseline is calculated using a mixed model approach, in which five possible statistical baseline models are tested for each household and the best fit model is selected based on performance across a set of proxy event days.

The fourth event on July 29 achieved the highest peak demand reduction of 1.05 kW per participant for a total peak reduction of 20.1 MW with line losses.

For 2022, the maximum potential capacity of the program was calculated to be 26.8 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 on load reduction is available in *Supplement 2: Evaluation*.

### 2023 Plans

Idaho Power will continue to actively market the A/C Cool Credit program to solicit new participants with a strong focus on recruiting customers that reside at a residence that currently has a switch that was installed for a previous occupant.

The company will explore opportunities to expand the A/C Cool Credit program by evaluating the potential for a Bring-Your-Own-Thermostat program option.

## Easy Savings: Low-Income Energy Efficiency Education

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (coupons) | 267 | 0 |
| Energy Savings (kWh) | 22,755 | 0 |
| 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 | $152,718 | $145,827 |
| Total Program Costs—All Sources | $152,718 | $145,827 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $1.448 | n/a |
| Total Resource Levelized Cost ($/kWh) | $1.448 | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |

### 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 provided $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 energy-saving kits (ESK) and corresponding educational materials to participants in 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 the Community Action Partner Association of Idaho (CAPAI), CAP agencies, the IPUC, and Idaho Power, this program 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 information for a customer satisfaction survey that can be completed online or mailed to CAPAI. Respondents are entered into a drawing for a gift card provided by CAPAI.

### Program Activities

The planning committee and contractors met virtually throughout 2021 to plan 2022 program updates. The group agreed to the following improvements that were implemented in 2022:

- Eligibility was expanded beyond only LIHEAP recipients to include all income-qualified Idaho Power customers with electric heat regardless of whether they had received LIHEAP assistance.
- In addition to providing HVAC system tune-ups and educating customers on their systems, HVAC contractors provided new energy saving items during their visits. By year end, the program accomplished the following:
    - Provided either a box of disposable furnace filters or individual washable furnace filters to 247 customers after showing them how to change or wash the filters and explaining the importance of clean furnace filters to HVAC operation
    - Installed 147 dusk-to-dawn LED bulbs in porch light fixtures
    - Wrapped pipes of 56 water heaters
    - Left 150 packages of dryer balls
    - Unwrapped and tested 175 air fryers with customer's commitment to use them at least twice per week in place of their ovens
    - Unwrapped and tested 41 counter-top microwaves with customers while including explanations of energy savings potential

Idaho Power sent coupons specific to each regional CAP agency for the 2022 program at the end of 2021. The company also sent helpful energy efficiency education materials for regional HVAC contractors to share with customers. A total of 267 coupons were redeemed by the end of the 2022 program year.

### Marketing Activities

Prior to 2022, Idaho Power sent a direct-mail postcard (Figure 8) to Idaho residential customers who previously received energy assistance to encourage them to take advantage of the program in 2022. Additionally, Facebook posts about the program were used during summer 2022 to promote coupon redemption.

The Easy Savings program is included under Savings for Your Home on the Idaho Power website in the Income-Qualified Customers section.

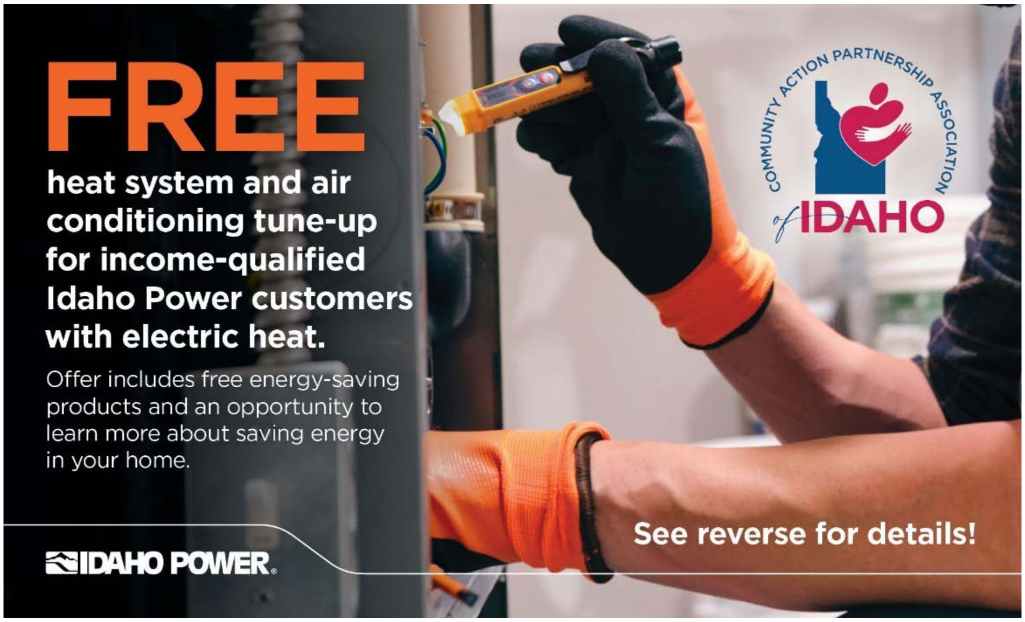



**Figure 8. Direct-mail postcard to Idaho residential customers for Easy Savings**

### 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.

For the HVAC tune up coupons redeemed in 2022, the program claimed approximately 61 kWh. For the pipes wrapped, the program claimed approximately 75 kWh. The savings are a weighted average of single family, multifamily, and manufactured home types from the 2022 energy efficiency potential study. The savings are weighted using the 2022 housing types from both the WAQC and Weatherization Solutions for Eligible Customers programs. The RTF provides deemed savings for direct-install LED lightbulbs. For the 800-lumen dusk-to-dawn exterior lights, the program claimed approximately 15 kWh.

### 2023 Plans

Each agency’s portion of the annual $125,000 payment will be made available in early 2023, once committee meetings have been completed and contractor guidelines are signed. Agencies will begin 2023 with their portion of this payment added to any unspent portion of the previous year’s payments. One agency overspent their portion of the annual Easy Savings funding in 2022. They plan to use 2023 Idaho Power funding to pay contractors for work done in 2022 for the program. This agency also received funding transferred from another CAP agency’s unused portion of their Easy Savings allotment for 2022.

Participating contractors will continue to discuss the importance of HVAC maintenance and incorporate education about saving energy with coupon recipients. They will answer questions about other ways to save energy in their homes.

## Educational Distributions

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (kits/giveaways) | 49,136 | 47,027 |
| | Energy Savings (kWh) | 3,741,954 | 2,930,280 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $1,061,898 | $433,963 |
| | Oregon Energy Efficiency Rider | $24,866 | $15,826 |
| | Idaho Power Funds | $49 | $0 |
| | Total Program Costs—All Sources | $1,086,813 | $449,790 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.037 | $0.019 |
| | Total Resource Levelized Cost ($/kWh) | $0.037 | $0.019 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 1.31 | 2.39 |
| | Total Resource Benefit/Cost Ratio | 1.62 | 3.10 |

### Description

Designated as a specific program in 2015, the Educational Distributions effort is administered through the REEEI and seeks to use low- and no-cost channels to deliver energy efficiency items with energy savings directly to customers. The goal for these distributions is to drive behavioral 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 behavioral 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.

#### *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 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
- Sticker and magnet pack (containing reminders about energy efficiency)


**Figure 9. Student Energy Efficiency Kit**

At the end 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, two nightlights, 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.


**Figure 10. Welcome Kit**

### Program Activities

#### *Nightlights as Giveaways*

Idaho Power continued to distribute LED nightlights to engage customers in discussions around energy-efficient behavior changes and home upgrades.

In-person events rebounded slowly but steadily throughout the year, affording Idaho Power staff and energy advisors the opportunity to distribute 5,920 nightlights along with an educational message. Nightlights were distributed to business and community leaders at civic events, aging customers at senior centers, secondary students at career fairs and during presentations, as well as many other groups at presentations and events throughout Idaho Power's service area.

**Figure 11. Nightlights as giveaways**

***Student Energy Efficiency Kit Program***

During the 2021–2022 school year, the vendor was responsible for SEEK recruiting activities. Idaho Power EOEAs continued to promote the program during their school visits and interactions with fourth- to sixth-grade teachers. The new curriculum, focusing on digital engagement, was well received and SEEK enrollments were strong. The vendor delivered a record 12,595 kits to 338 classrooms in 174 schools within Idaho Power's service area. This resulted in 2,349 MWh of savings.

***Welcome Kits***

Idaho Power continued to contract with a third-party vendor to distribute energy efficiency kits to the company's first-time customers. In 2022, after collaboration with EEAG, the kit contents were adjusted to improve cost-effectiveness. Rather than two 800-lumen lightbulbs, two 1,600-lumen LED lightbulbs and one nightlight, each recipient received four 1,100-lumen lightbulbs and two nightlights.

The company sent nearly 31,000 Welcome Kits to customers in 2022—down slightly from the quantity delivered in the previous two years. Idaho Power continues to receive positive customer feedback indicating these kits are well-received.

## Marketing Activities

#### *Nightlights as Giveaways*

Nightlights are not marketed as a separate measure, but energy advisors used them to facilitate energy efficiency conversations during customer visits. Nightlights have also become an outstanding way to engage customers at events and presentations as energy advisors report they are a sought-after item.

#### *Student Energy Efficiency Kit Program*

During the 2021–2022 school year, the vendor 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. The kits are, however, 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. If outside vendors were used to assist with distribution, the cost-effectiveness calculations include all vendor-related charges.

The UCT and TRC for the program are 1.31 and 1.62 respectively.

#### *Nightlights as Giveaways*

Idaho Power used the third-party evaluator's calculated savings of 12 kWh per nightlight as explained in the Welcome Kit 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 2021–2022 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 63%. 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 2021–2022 school year, the savings for each kit was approximately 187 kWh annually per household on average, and the program saved 2,349,312 kWh annually. A copy of the report is included in *Supplement 2: Evaluation*.

#### *Welcome Kits*

For the four 1100-lumen LED lightbulbs included in the kit, Idaho Power used the RTF's giveaway deemed savings value of 4.79 kWh per lightbulb. For the nightlight, Idaho Power used the third-party evaluator's calculated savings of 12 kWh per nightlight, which was identified using survey data as part of a 2020 evaluation. The annual savings for each kit is 43.16 kWh. With the implementation of *Energy Independence and Security Act of 2007* (EISA) after June 30, 2023, Idaho Power will no longer claim savings for the screw-in LEDS.

In 2022, the Welcome Kits were not fully cost-effective due to additional erosion of lighting savings. After consulting the EEAG in 2021, the decision was made to keep this educational program, but to only include the cost-effective portion associated with those energy savings in the Educational Distribution program; the remainder of the kit costs are included in the REEEI budget (see Other Programs and Activities section).

### 2023 Plans

#### *Nightlights as Giveaways*

Nightlights will continue to be the primary opportunity to garner savings in conjunction with educational discussions and customer conversations. Field staff will look for opportunities to discuss enhancements in LED technology (dusk-to-dawn sensors, etc.) 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. The company will work with the vendor to implement process and curriculum enhancements based on suggestions received from teachers, students, and parents.

The company will continue to leverage the positive relationships Idaho Power's EOEAs have within the schools to maintain program participation levels.

#### *Welcome Kits*

Idaho Power will continue to offer Welcome Kits to first-time customers. For the first half of 2023, the kit configuration will continue to take advantage of the RTF savings associated with

1,100-lumen lightbulbs. On June 30, in conjunction with the elimination of lighting savings due to EISA standards, the kit will be reconfigured—rather than four 1,100-lumen lightbulbs, each kit will contain two 800-lumen lightbulbs. The Welcome Kits will cross-promote other energy efficiency programs and educate and encourage new customers to adopt energy-efficient behaviors upon moving into their new homes. The Educational Distributions program will continue to count the savings and pay for the cost-effective energy-saving portion of each kit, while the remaining costs associated with the kits will be included in Idaho Power's REEEI efforts.

#### *Other Educational Distributions*

Idaho Power will continue to look for opportunities to engage customers with new technologies that stress the importance of energy-efficient behaviors at home. Idaho Power will continue with its efforts to identify a marketplace platform that will engage and educate customers while promoting efficient technologies that may not fold neatly into other program offerings.

## *Energy Efficient Lighting*

| | | 2022 | 2021* |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (lightbulbs) | 370,739 | 0 |
| | Energy Savings (kWh) | 1,728,352 | 0 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $505,430 | $41,438 |
| | Oregon Energy Efficiency Rider | $29,475 | $2,194 |
| | Idaho Power Funds | $76 | 0 |
| | Total Program Costs—All Sources | $534,982 | $43,631 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.030 | n/a |
| | Total Resource Levelized Cost ($/kWh) | $0.040 | n/a |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 1.68 | n/a |
| | Total Resource Benefit/Cost Ratio | 1.52 | n/a |

* Expenses incurred in 2021 in preparation for the relaunch of the program in 2022.

### Description

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

After the BPA-sponsored Simple Steps program ended in September 2020, Idaho Power pursued the start of its own lighting buydown program. Shelf studies showed that specific retail channels in the region were still selling inefficient lighting products. The new lighting buydown program, launched in late December 2021, provides ENERGY STAR LED lightbulb and light fixture incentives at grocery, dollar, mass merchandise, and small hardware stores, and provides ENERGY STAR LED light fixture incentives at membership club and do-it-yourself hardware stores. By following this model, Idaho Power was able to achieve higher savings by focusing on sales at retailers that traditionally offered more inefficient lighting products, helping to ensure the program remained cost-effective.

In 2022, LED lightbulbs comprised 74% of the program's sales for the year, a significant decrease from the 93% of lightbulb sales in 2020. LED fixtures comprised approximately 26% of overall program sales.

In 2022, Idaho Power worked with 11 participating retailers, representing 100 individual store locations in its service area. Of those participating retailers, 66% of sales were from grocery, dollar, and mass-merchandise stores, 23% from do-it-yourself hardware stores, 9% from small hardware stores, and 2% from membership clubs. Many rural sales came from these smaller retailers that serve hard-to-reach customers. It was important to include several store types across Idaho Power's service area to ensure all customers have access to efficient lighting options.


**Figure 12.** **Lighting shelf store display**

### Marketing Activities

In 2022, the program contractor promoted discounts with special product placement and signs. Monthly visits to check stock and ensure point-of-purchase signs were placed on qualifying products were conducted. In addition, a Facebook and Twitter post went out in March using updated graphics. A lighting tip was also included in the August *Home Energy Report*.

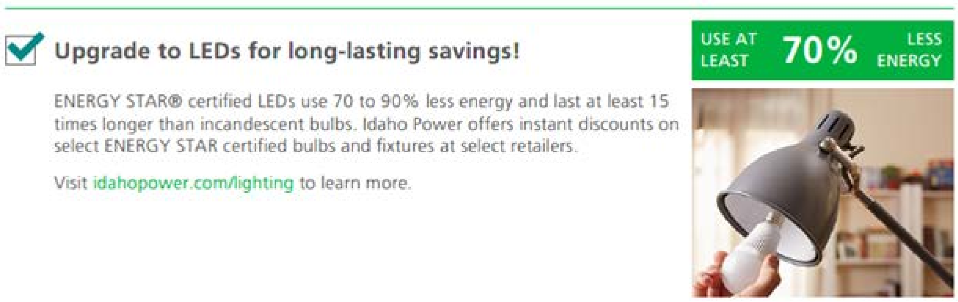



**Figure 13. Home Energy Report tip**

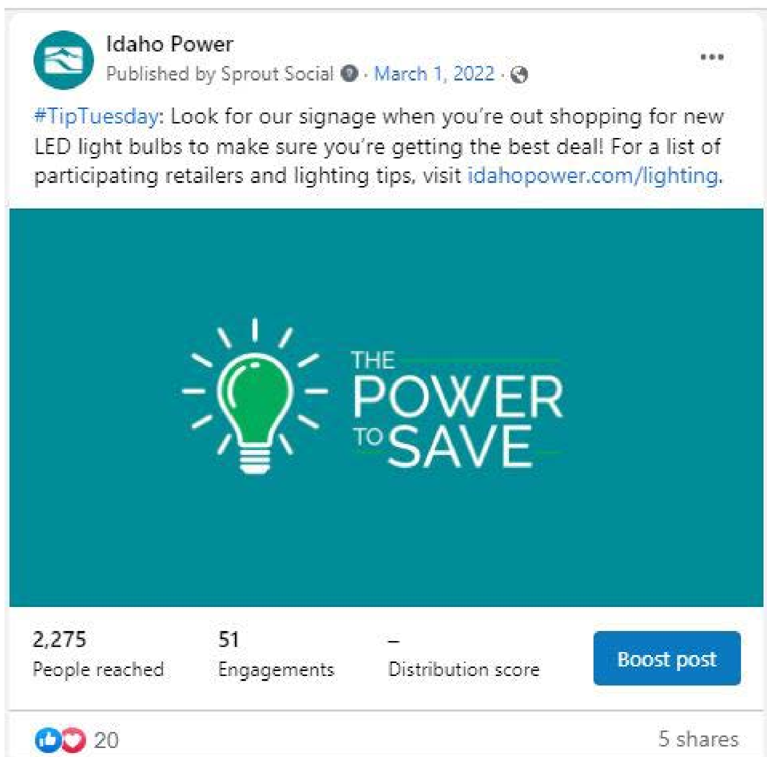



**Figure 14. Lighting post**

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.

### Cost-Effectiveness

The UCT and TRC ratios for the program are 1.68 and 1.52, respectively. In September 2020, the RTF updated the savings assumptions for residential lighting. At the time of the update, the US Department of Energy (DOE) had issued a Final Rule that essentially circumvented the previous 45 lumen-per-watt backstop for general service incandescent lamps. As a result, the RTF workbook version 9.0 (and subsequent updates) assumed no federal standards were in place and the analysis was based on the NEEA's 2019 lighting market shelf study. Due to the lower savings in the workbook, the BPA decided not to resume the Simple Steps program.

As described at the November 2020 EEAG meeting, Idaho Power reached out to the Energy Trust of Oregon (ETO) to learn more about the retail lighting program the organization was planning to launch to replace the Simple Steps program. Based on its 2019 lighting market shelf study, NEEA found that 100% of lightbulbs sold in membership clubs were LEDs while only 46% of the lightbulbs sold in grocery, dollar, and mass-merchandise stores were LED. RTF blended this information to determine the current market baseline for the region. ETO decided to focus their new retail lighting program on the grocery, dollar, mass-merchandise stores retail channel because of the higher probability of selling inefficient lightbulbs and the potential to move the market further.

Idaho Power received ETO's modified RTF lighting workbook version 9.3 in 2021. By updating the market baseline, the annual savings for general purpose lightbulbs in the 250–1,049 lumen range increased from 0.91 kwh to 4.50 kWh. The annual savings for reflector lightbulbs in the 250–1,049 lumen range increased from 1.15 kWh to 4.65 kWh. Idaho Power worked with the third-party implementer to design a retail lighting program targeted to grocery, dollar, mass-merchandise, and small hardware stores. Additionally, LED fixtures were included in the program and offered across all retail channels.

In January 2021, Executive Order 13990 instructed all agencies to review existing regulations issued or adopted between January 2017 and January 2021. The DOE re-evaluated its prior determination and proposed codifying the 45 lumen-per-watt backstop requirement. In April 2022, the DOE issued a Final Rule that reinstituted EISA and the expanded general service lamp definition and the 45 lumen-per-watt backstop effective July 2022. The DOE enacted a progressive enforcement policy with different ramp up times for both manufacturers/importers and retailers/distributors. For the distribution and sale of non-compliant lightbulbs, warnings would be issued from January 1 to February 28, 2023. Reduced penalties would be issued between March 1 to June 30, 2023, with full enforcement and penalties issued as of July 1, 2023.

The RTF reviewed and updated the savings assumptions for residential lighting in September 2022. Per the Northwest Power and Conservation Council (NWPCC) policy, the RTF modeled savings based on the current effective standards. With the exception of some compact fluorescent lightbulbs, there are not many “minimally compliant” options available. Based on the market data, it was determined the baseline would be comprised almost entirely of LEDs. As a result, the RTF removed the retail and by-request delivery channels. Idaho Power will begin using the newest RTF workbook version 11.0 after June 30, 2023.

For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

### 2023 Plans

Idaho Power, with input and support from EEAG, decided to continue offering the lighting buydown program through June 30, 2023. After that date, the DOE will begin enforcing federal EISA lighting standards with financial penalties to those retailers that continue to sell inefficient lightbulbs that do not meet the new 45 lumen-per-watt requirement. It is assumed that after that date, most retailers will no longer sell inefficient lightbulbs, negating the need for a program to influence lighting purchasing decisions. Before the July 1 enforcement date, it is assumed that many retailers will have inefficient inventory to offload, thus making an incentive to purchase efficient lightbulbs more valuable. Idaho Power will perform periodic reviews of participating retailers across its service area to validate if inefficient lightbulbs are still sold. If it is determined that a retailer is no longer offering inefficient lightbulbs, the retailer will be removed from the program.

## *Energy House Calls*

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 52 | 11 |
| Energy Savings (kWh) | 54,516 | 14,985 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $36,734 | $17,375 |
| Oregon Energy Efficiency Rider | $1,378 | $882 |
| Idaho Power Funds | $51 | $0 |
| Total Program Costs—All Sources | $38,163 | $18,257 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.062 | $0.105 |
| Total Resource Levelized Cost ($/kWh) | $0.062 | $0.105 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.70 | 0.43 |
| Total Resource Benefit/Cost Ratio | 0.77 | 0.50 |

### 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 BPA; installing LED lightbulbs; testing the temperature set on the water heater; installing water heater pipe covers when applicable; installing one bathroom faucet aerator, one kitchen faucet aerator; and leaving two replacement furnace filters with installation instructions, as well as 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 exterior, moderate- and high-use areas of the home; to replace only incandescent and halogen lightbulbs; and to install bathroom aerators and showerheads only if the upgrade can be performed without damaging 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

Energy House Calls is one of Idaho Power's longest-running energy efficiency programs, available to electrically heated manufactured homes only and limited to one visit per home for the life of the program. With a limited number of available homes that meet the eligibility criteria, the program has experienced a steady and sustained decline in participation indicating market saturation. Due to the program becoming non-cost-effective, with the support of EEAG, the program was closed to new participants as of June 30, 2022.

Contractors were given until December 31, 2022, to service all customers that enrolled prior to the June 30 closing, including any remaining from the backlog of projects that had accumulated while the program in-home work was temporarily suspended due to COVID-19 in 2020 and 2021. While not everyone from the backlog of customers decided to move forward with their participation in the program, contractors contacted every customer to ensure they were informed about the program closing and had ample opportunity to have work done before the December 31 deadline.

In 2022, 52 homes received products and/or services through the program, resulting in 54,516 kWh savings. Of the participating homes, 43% were in Idaho Power's South–East Region, 19% were in the Capital Region, and 38% were in the Canyon–West Region.

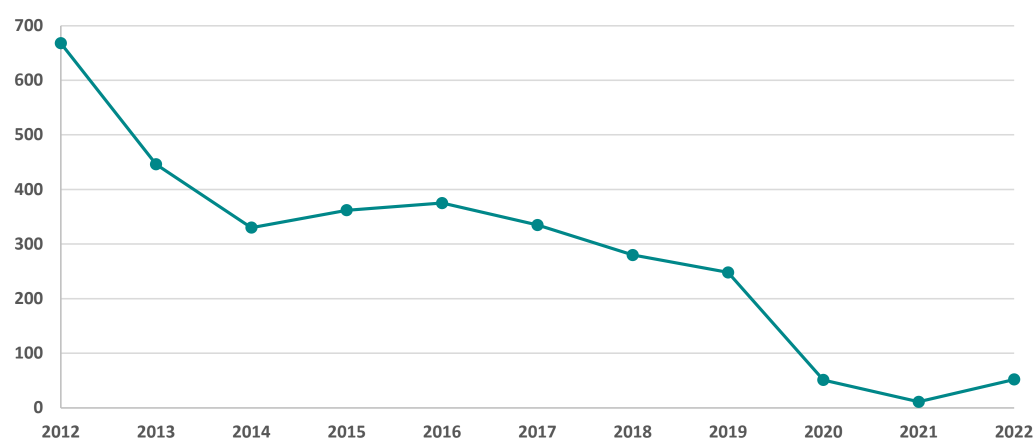



**Figure 15. Participation in the Energy House Calls program, 2012–2022**

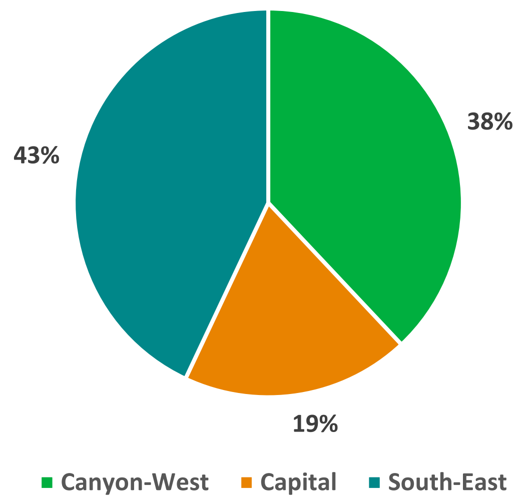



**Figure 16. Participation in the Energy House Calls program, by region**

***Duct-Sealing***

Some customers who applied for the Energy House Calls program could not be served because their ducts did not require duct-sealing or could not be sealed for various reasons. These jobs were billed as a test-only job. On some homes, it was either too difficult to seal the ducts, or the initial duct blaster test identified the depressurization to be less than 150 cubic feet per minute (cfm) making duct-sealing unnecessary. Additionally, if after sealing the duct work the contractor was unable to reduce leakage by 50%, the contractor would 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. In 2022, because Idaho Power offered direct-install measures in addition to the duct-sealing component, all homes were reported. While some homes were not 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 52 homes that participated in 2022, six 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 was necessary, it was 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 needed replacing in addition to the duct-sealing, it was charged as an x-over. When a home required that the existing belly-return system be decommissioned and a new return installed along with the duct-sealing, it was billed as a complex system. A complex system that also requires the installation of a new x-over as well as duct-sealing is billed as a complex system and x-over job. Figure 17 shows the job type totals (test and seal versus x-over) for the 2022 Energy House Calls program.

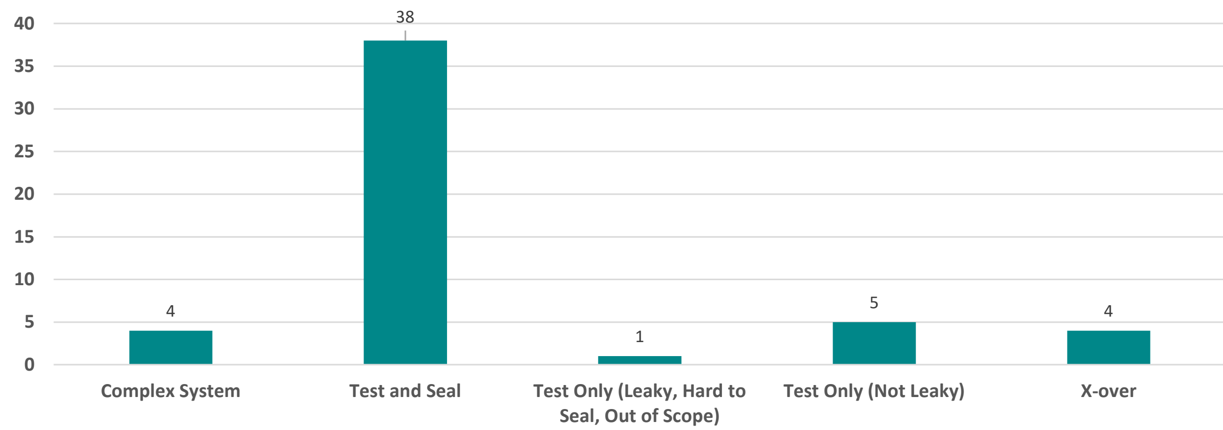



**Figure 17. Energy House Calls participation by job type**

#### *Direct-Install Measures*

In 2022, contractors installed 265 LED lightbulbs, no showerheads, one bathroom aerator, three kitchen aerators, and pipe wrap on 21 water heater pipes.

### Marketing Activities

Because the program became non-cost-effective and was ending on June 30, 2022, all marketing efforts were suspended for 2022. Idaho Power added a disclaimer on the Energy House Calls program website once the program ended advising that the program had ended but that there were other assistance programs available for duct-sealing through the WAQC or Weatherization Solutions for Eligible Customers programs, or duct-sealing measures included in the Heating & Cooling Efficiency Program (H&CE Program).

### Cost-Effectiveness

The UCT and TRC ratios for the program are 0.70 and 0.77, respectively.

The RTF is the source of all savings assumptions for the program. Savings for the LED lightbulbs increased from 5.65 kWh to 12.12 kWh based on updated lighting assumptions. In 2021, the RTF reviewed aerator savings. Because of the uncertainty around the relationship between hot water savings and the savings associated with aerators, the RTF deactivated the measure. Therefore, there are no savings associated with the aerators in 2022.

In 2022, Idaho Power used the same RTF savings for duct-sealing in manufactured homes as were used in 2021. The savings were approximately 1,081 kWh per home. In December 2021, the RTF reviewed and updated the savings associated with manufactured home duct-sealing based on program evaluations around the region. The updated manufactured duct-sealing savings is approximately 888 kWh per home. Due to the timing of the adoption of the new workbook, Idaho Power did not use the updated workbook to calculate savings for the program in 2022. However, the new workbook was used to analyze the future cost-effectiveness for the program. Due to the declining savings of both the duct-sealing and direct-install items as well as the increasing costs associated with offering a free service for program participants, it was determined the program would continue to be non-cost-effective in its current format. With the support of EEAG, the program was closed to new participants as of June 30, 2022. The updated manufactured home duct-sealing savings of 888 kWh per home will be used for future participants of the Heating & Cooling Efficiency Program (H&CE Program).

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

### 2023 Plans

With the Energy House Calls program ending, eligibility for the duct-sealing measure incentive within the H&CE Program has expanded to include customers that reside in an all-electric manufactured home. Additionally, both the WAQC and Weatherization Solutions for Eligible Customers programs include duct-sealing as approved measures when needed.

## *Heating & Cooling Efficiency Program*

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (projects) | 1,080 | 1,048 |
| | Energy Savings (kWh) | 1,310,260 | 1,365,825 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $636,597 | $600,636 |
| | Oregon Energy Efficiency Rider | $28,960 | $34,522 |
| | Idaho Power Funds | $459 | $25 |
| | Total Program Costs—All Sources | $666,016 | $635,182 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.050 | $0.044 |
| | Total Resource Levelized Cost ($/kWh) | $0.180 | $0.155 |
| **Benefit/Cost Ratios*** | | | |
| | Utility Benefit/Cost Ratio | 0.98 | 1.14 |
| | Total Resource Benefit/Cost Ratio | 0.30 | 0.36 |

*2021 and 2022 cost-effectiveness ratios include evaluation. If evaluation expenses were removed from the program's cost-effectiveness, the 2021 UCT and TRC would be 1.19 and 0.36, respectively, and the 2022 UCT and TRC would be 1.00 and 0.30, respectively.

### Description

Initiated in 2007, the objective of the 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, landlords, 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 and for new homes are summarized in tables 9 and 10, respectively.

See idahopower.com/heatingcooling for a complete description of the program.

**Table 9. Measures, conditions, and incentives—existing homes**

| Existing Equipment Requirement | New Equipment or Services | Customer Incentive | Contractor Stipend | New Equipment or Services Requirements[1] |
|---|---|---|---|---|
| Ducted air-source heat pump | Ducted air-source heat pump | $ 250 | $ 50 | Minimum efficiency 8.5 HSPF |
| Oil or propane heating system | Ducted air-source heat pump | 400 | 50 | Minimum efficiency 8.5 HSPF<br>Natural gas not available |
| Electric (forced-air or zonal) heating system) | Ducted air-source heat pump | 800 | 50 | Minimum efficiency 8.5 HSPF |
| Ducted air-source heat pump | Ducted open-loop water-source heat pump | 500 | 50 | Minimum efficiency 3.5 COP |
| Electric (forced-air or zonal), oil, or propane heating system | Ducted open-loop water-source heat pump | 1,000 | 50 | Minimum efficiency 3.5 COP<br>Natural gas not available when existing equipment is oil or propane heating system |
| Air-source heat pump | Ducted ground-source heat pump[2] | 1,000 | | Minimum efficiency 3.5 COP |
| Electric zonal system, electric furnace, or an oil or propane furnace | Ducted ground-source heat pump[2] | 3,000 | | Natural gas not available when existing equipment is oil or propane heating system<br>Minimum efficiency 3.5 COP |
| n/a | Central A/C[2] | 50 | | Minimum 15 SEER but <17; minimum 12 EER |
| n/a | Central A/C[2] | 150 | | Minimum 17 SEER; minimum 13 EER |
| Zonal electric heating system | Ductless air-source heat pump | 750 | | Minimum one indoor unit in main living area |
| Zonal electric heating system | Ductless air-source heat pump | 750 | | Minimum one indoor unit in main living area |
| Electric forced-air heating system or heat pump | Duct-sealing services (single family or manufactured home[2]) | 350 | | |
| Permanent split capacitor air handler motor | Electronically commutated motor | 50 | 150[3] | Oil, propane or natural gas forced-air heat, electric forced-air heat, or heat pump |
| n/a | Evaporative cooler | 150 | | 2,500 CFM minimum airflow |
| Electric storage water heater | Heat pump water heater | 300 | | Tank size less than or equal to 55 gallons |
| Electric heating system | Smart thermostat | 75 | | Internet connected |
| Zonal or central A/C or heat pump | Whole-house fan | 200 | | 2,000 CFM minimum airflow |

[1]See idahopower.com/heatingcooling for full requirements
[2]Idaho customers only
[3]Contractor incentive

HSPF = Heating Seasonal Performance Factor
COP = Coefficient of Performance
SEER = Seasonal Energy Efficiency Ratio
EER = Energy Efficiency Ratio

**Table 10. Measures, conditions, and incentives—new homes**

| New Equipment | Customer Incentive | Contractor Stipend | Requirements |
|---|---|---|---|
| Ducted air-source heat pump | $ 400 | $ 50 | Minimum efficiency 8.5 HSPF; natural gas not available |
| Ducted open-loop water-source heat pump | 1,000 | 50 | Minimum efficiency 3.5 COP; natural gas not available |
| Ducted ground-source heat pump[1] | 3,000 | | Minimum efficiency 3.5 COP; natural gas not available |
| Central A/C[1] | 50 | | Minimum 15 SEER but <17; minimum 12 EER |
| Central A/C[1] | 150 | | Minimum 17 SEER; minimum 13 EER |

[1]Idaho customers only

Idaho Power requires licensed contractors to perform the installation services related to these measures, except evaporative coolers, heat pump water heaters, and smart thermostats. To qualify for the ducted air-source heat pump (ASHP), ducted open-loop water source heat pump, ductless ASHP, and duct-sealing incentives, 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.

A third-party contractor reviews and submits incentive applications for payment using a program database portal developed by Idaho Power. The third-party contractor also provides technical and program support to customers and their contractors and performs on-site and off-site verifications.

## Program Activities

Program performance is substantially dependent on the contractors' abilities to promote and leverage the heat pump measures offered. Idaho Power developed participating contractors currently in the program while adding three new contractors in 2022. The program specialist frequently engaged with contractors to discuss the program and provided six on-site training sessions with technical and market information.

In 2020, Idaho Power conducted an exercise described as journey mapping: a team of employees met periodically for three months to develop improvements to the program that would improve the customer experience when participating in the program. Recommendations included creating new layouts for the program's 10 online PDF application forms. Idaho Power updated one of the 10 forms in 2021 and completed updates to the remaining nine forms in 2022.

Idaho Power began offering two new measures through the program on July 1, 2022. The measures provided a cash incentive to Idaho customers who installed a central A/C or a ground-source heat pump. The incentives apply to both existing homes and new construction.

During the development stage of these measures, the company provided updates and requested input from EEAG at quarterly meetings. EEAG's feedback regarding these measures was positive.

The number of H&CE Program incentives paid in 2022 are listed in Table 11.

**Table 11. Quantity of H&CE Program incentives in 2022**

| Incentive Measure | Project Quantity |
|---|---|
| Ducted Air-Source Heat Pump | 181 |
| Open Loop Water-Source Heat Pump | 3 |
| Ductless Heat Pump | 243 |
| Evaporative Cooler | 14 |
| Whole-House Fan | 113 |
| Electronically Commutated Motor | 28 |
| Duct-Sealing | 2 |
| Smart Thermostat | 449 |
| Heat Pump Water Heater | 26 |
| Central A/C | 19 |
| Ground-Source Heat Pump | 2 |

## Marketing Activities

Idaho Power used multiple marketing tactics for its H&CE Program promotion in 2022.

Idaho Power sent two program-related postcards to a targeted customer group determined to use electric heat: 8,088 customers received postcards in February and September. The company mailed a bill insert to 306,888 residential customers in April and 298,861 residential customers in October.

In February, the company emailed information about the H&CE Program to approximately 180,938 residential customers. The promotion was opened by over 89,318 customers and received approximately 2,039 clicks to the H&CE Program website. Idaho Power also sent an email promotion in August to 209,830 residential customers; the email was opened by 107,549 customers and received 4,987 clicks to the web page.

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 1,539,162 impressions and 17,535 clicks to the H&CE Program web page in February and 3,046,748 impressions and 2,319 clicks in September. (An impression is a count of every time the ad is seen; a single person who sees the ad 10 times counts as 10 impressions.)

A pop-up ad in the company's My Account platform—a portal where customers login to see their energy usage and bill information—was also used in February. Customers who logged into My Account saw a promotion for the H&CE Program pop up on their screens. A total of 77,646 customers were shown the pop-up and 2,052 clicked through to learn more.

Program information was also included in energy efficiency collateral mailed in the new customer Welcome Kits. The program was also featured on Idaho Power's website homepage in February.

The spring/summer edition of the *2022 Energy Efficiency Guide* distributed through local newspapers featured an article on whole house fans. The *Home Energy Report* listed heating and cooling tips on the back page throughout the year (see the HER Program section). The two new measures listed above, central A/C and ducted ground-source heat pump, were also added to the suite of program collateral.

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

In 2022, the H&CE Program had a UCT of 0.98 and TRC of 0.30. In 2022, the program incurred evaluation expenses related to the impact and process evaluation that occurred in late 2021. If the amount incurred for the evaluation was removed from the program's cost-effectiveness, the UCT would be 1.00, while the TRC would be 0.30.

Overall, while participation increased slightly from 1,048 participants in 2021 to 1,080 participants in 2022, the total savings decreased by 55,565 kWh year over year. The decrease in overall savings was largely due to the lower participation in the electronically commutated motor (ECM) measure and the reduction in connected thermostat savings in response to the evaluation recommendation to not claim savings for ASHPs that claim additional commissioning, controls, and sizing (CCS) savings. Savings were also reduced for evaporative coolers in response to the evaluation recommendation to adjust the savings with a net-to-gross (NTG) factor of 44.4%. These reductions in savings were slightly offset by the increase in participation in the ductless heat pump (DHP) measure and the addition of two new measures in 2022, ground-source heat pumps and high-efficiency A/Cs.

The RTF is the source of most measure savings assumptions within the program. In general, most savings assumption did not change in 2022 over 2021 with the exception of a few measures in response to recommendations by the evaluators in the recent impact evaluation. More information regarding those recommendations and adjustment are described in the Evaluation section below. Some measures within the program do not pass the UCT; however, these measures, with the exception of DHPs, would pass the UCT if administration costs were not included in the measure's cost-effectiveness. Most measures are not cost-effective from a TRC perspective. The program itself has a cost-effectiveness exception with the OPUC under UM 1710. Due to the changes to federal standards for ASHP, the program will be modified in 2023 to incorporate the updated savings assumptions, new measures, and recommendations from the 2021 evaluation.

For detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Evaluations

In 2021, Idaho Power contracted with a third-party consultant to conduct impact and process evaluations for the 2020 program year of the H&CE Program in the Idaho and Oregon service area. The complete analysis report was published in the 2021 *Supplement 2: Evaluation*.

Below are the impact and process evaluation recommendations made by the evaluators followed by a description of how Idaho Power responded in 2022.

#### *Applications/Processing*

*It was recommended Idaho Power: require customers to fill out application forms consistently for all projects; review each application to ensure information requested on the application forms is provided and that it meets the requirements; improve methods when collecting information using the web and application forms; verify information customers provide on the whole-house fan application forms and ensure those forms are enforced.* Idaho Power requires customers to consistently provide information requested on the application forms, per the Terms and Conditions. Idaho Power cannot always control what customers input on the forms; follow-up and verification is performed only on the critical data. Idaho Power will continue reviewing all application forms for any missing or inaccurate information and obtain missing or inaccurate information from the customer or the installing contractor if used. Idaho Power will continue comparing all information provided to ensure it meets the measure requirements. Idaho Power routinely improves the Idaho Power program website and the application forms to promote optimal usability.

#### *Savings Assumptions/Calculations*

*The evaluators recommended Idaho Power round up savings values to the nearest kWh for Regional Technical Forum (RTF) approved measures.* Idaho Power has received conflicting recommendations from past evaluators to use RTF deemed savings values to two decimal places. Idaho Power has done so for all RTF-sourced deemed savings values. The company has decided not to apply this recommendation to maintain consistency across all programs.

*It was recommended Idaho Power apply a 44.4% NTG to the claimed savings of the evaporative cooler incentive to account for displaced refrigerated air. The evaluators referenced a Technical*

*Reference Manual from Public Company of New Mexico 2015. They also recommend Idaho Power establish a Net to Gross specific to the Idaho Power service area.* Idaho Power has applied the 44.44% NTG for the evaporative coolers that had an incentive in 2022. When the program is updated in 2023, the application will be updated to ask questions around the displaced refrigerated air in order for the company to calculate the actual NTG percentage for the offering.

*The evaluators recommended Idaho Power continue to use the literature review workpaper provided by the IDL when claiming savings for the ECM incentive.* Idaho Power will continue to use the IDL workpaper along with an Idaho Power savings calculator.

*The evaluators recommended Idaho Power integrate the modeling results contained in the workpaper provided by the IDL when claiming savings for the whole-house fan incentive.* Idaho Power has started collecting the data necessary in its application forms to implement this method. The company reviewed modeling the savings results using the IDL workpaper and found the results to be similar to the 446 kWh currently being claimed for the measure.

*Another recommendation was that Idaho Power ensure the measure level savings applied to the heat pump water heater matches the RTF workbook interactive components such as cooling and heating interactions.* The savings calculation was updated before reporting the *DSM 2021 Annual Report* savings to match the savings as shown in the RTF workbook version 5.3. They were used again in 2022.

*The evaluators recommended Idaho Power refrain from claiming smart thermostat savings for smart thermostats that get connected to heat pumps that are installed to Performance Tested Comfort System (PTCS) standards and Idaho Power is claiming the PTCS savings.* Idaho Power has removed smart thermostat savings that are included with heat pump installations in which PTCS savings are also claimed.

*Another recommendation was that Idaho Power use the evaluator's billing analysis to claim savings for ducted air-source heat pumps upgrade measure as the alternative to the current savings which combined the RTF's ducted air-source heat pump upgrades with the RTF's deactivated CCS savings workbook.* The savings from the billing analysis differed significantly from the RTF deemed savings value. The savings for ASHP upgrades alone range from 20 to 107 kWh annually. CCS savings are additive and would increase the upgrade savings to 556 to 1,002 kWh. The billing analysis conducted by the evaluators showed that savings were approximately 1,263 kWh. While the evaluators were unable to separate the estimated savings between the ASHP upgrade and the CCS savings, the analysis seems to indicate that CCS savings are occurring. For 2022, Idaho Power continued to use the RTF savings and CCS savings. Due to the changes in federal standards that went into effect in January 2023, Idaho Power will remove the upgrades as a standalone measure from the program in 2023.

*The evaluators recommended Idaho Power continue to use the RTF's savings values for the ducted air-source heat pump conversion measure. In addition, due to the RTF deactivation of the CCS workbook and the results of the Evaluator's billing analysis, the Evaluators recommend that Idaho Power not claim additional savings for those projects.* While the billing analysis conducted for the ASHP conversions could not show significant savings for CCS, the billing analysis for ASHP upgrades showed significantly higher savings than the RTF upgrade savings with CCS. That particular billing analysis seemed to indicate CCS savings are occurring. Additionally, Bonneville Power Administration (BPA) is continuing to use deactivated CCS saving for ASHPs that undergo PTCS. Idaho Power will continue to follow BPA's PTCS specifications for CCS. For 2022, Idaho Power used the savings from the RTF workbook version 5.1 and CCS savings. Due to the changes in federal standards that went into effect in January 2023, the RTF updated the ASHP workbook. With the recently updated RTF workbook version 7.1, the ASHP included a mix of program practices, which includes programs with and without CCS requirements, into the development of the deemed savings values. Going forward, Idaho Power will not be adding CCS savings since it will be embedded in the ASHP savings from the RTF.

***Training***

*The evaluators recommended Idaho Power provide additional training to the Participating Contractors administering the ducted air-source heat pump measure to ensure requirements are being met for the Performance Tested Comfort System savings adder from the RTF.* Idaho Power will continue providing additional training to contractors to help them meet program requirements for this measure.

*It was recommended Idaho Power reach out to existing contractors using trainings, in-person visits, and other methods to maintain and develop relationships.* Idaho Power continues to provide trainings and arrange visits with contractors to maintain and grow the relationships. Idaho Power's relationships with the contractors has been a strong asset to the program's performance.

*The evaluators recommended Idaho Power provide additional efforts to provide educational training to build contractor awareness of the program and its requirements.* Idaho Power will continue to provide training to existing and new contractors to increase their participation in the program. Idaho Power understands the reasons for a contractor's lack of participation can be complex. The program does require contractors to have existing technical knowledge of heat pumps to perform the program requirements. To help address that need, Idaho Power works directly with contractors to increase their technical knowledge. As additional Idaho Power resources become available, those resources will be made available to assist contractors.

The evaluators recommended Idaho Power provide instructional education for homeowners self-installing smart thermostats through the program. It was also recommended that the incentive be increased to encourage the homeowners to have their smart thermostat installed properly to their equipment. Idaho Power provides educational guidance on the measure web landing page describing the importance of setting up key energy impacting features on these thermostats. An increase in the incentive amount is not planned. This is due to cost-effectiveness constraints and the belief that the homeowner's technical ability is not proportional to the incentive amount.

***Marketing/Outreach/Incentives***

*Another recommendation was that Idaho Power invest in more marketing and outreach with timing sensitive to customer's propensity to be engaged in home upgrade projects. A focus on Smart Thermostats was also recommended.* Idaho Power believes the amount and types of marketing tactics being used by the program are correct and have appropriate timing. Measure level and portfolio-level tactics are used. Idaho Power continues to adjust the program's marketing tactics and frequency to maximize the effectiveness of the messaging content.

*It was recommended Idaho Power create a qualified products list for the smart thermostat incentive to ensure the features required by the RTF are present on the thermostat brands and models that receive the incentive.* The smart thermostat products available and their features are evolving constantly, rendering a qualified products list impractical. Idaho Power does consider all information provided by the RTF and will adjust this measure as necessary. Additionally, with the recent updates to smart thermostat savings from the RTF, the retail do-it-yourself option will need to be modified or removed from the program offering.

*Another recommendation was that Idaho Power increase the customer incentive amounts for existing measures and expand the number of measures offered. An increase to the contractor stipend was also recommended for heat pump installations.* Idaho Power continues to expand the program measures, most recently with two new measures added July 1, 2022. Incentive amounts and contractor stipends are periodically reviewed. Idaho Power will continue to review these incentives and stipend amounts and will adjust them as necessary, considering cost-effectiveness of the measure and the program as a whole.

*It was recommended Idaho Power engage with the RCEAs to obtain their help in promoting the program.* Idaho Power has engaged with its residential and commercial energy advisors on this program and will continue to do so in the future; residential and commercial energy advisors have been and continue to be a helpful resource to keep vendors and customers informed about the program measures.

*The evaluators recommended working with the supply chain to understand the local availability of ducted heat pumps and their associated HSPFs. An incentive for distributors was recommended to motivate distributors to encourage contractors to install higher efficient units.* Idaho Power interacts with and understands the local heat pump supply chain and their mix of heat pumps and associated HSPFs. Idaho Power does not believe a distributor tier incentive is needed to motivate contractors into selling higher efficiency DHPs because the installing contractors already determine what the best solution is for their customer's individual needs.

#### *RTF Workbooks*

*The evaluators recommended Idaho Power continue to require additional documents to verify the components for PTCS certification to ensure future RTF workbooks remain applicable.* This recommendation applies to the ducted ASHP measure. Idaho Power will continue to require and collect this information using the required program forms. For example, the evaluator suggested collecting additional documents listing heat pump British thermal units (BTU) outputs at 17° F and 47° F. These outputs are contained in the required Air-Conditioning, Heating, and Refrigeration Institute (AHRI) Certificate of Product Ratings. The program forms were updated in 2022 and reflect the new PTCS standard released in April 2022 by the BPA.

*The evaluators recommended Idaho Power continue analyzing impacts of the RTF's commissioning, controls, and sizing (CCS) workbook through measurement or billing analysis until the RTF presents a new workbook to replace the workbook deactivated in 2020.* [This recommendation applies to the ducted ASHP measure.] With the recently updated RTF workbook version 7.1, a mix of program practices were embedded in the savings, including programs with and without CCS requirements. However, the program will continue to require the participating contractors to adhere to CCS as it has since the inception of the measure. In early 2023 the program will broadcast the new BPA CCS specifications that were launched April 2022. This will involve contractor training, incentive application form redesign, and internal systems and website edits. BPA continues to advocate for proper CCS and continues to research its impact on savings. Idaho Power will look to the BPA research to see what can be done for CCS going forward.

*Another recommendation was that Idaho Power continue to use the RTF Connected Thermostat workbook to evaluate savings for the Smart Thermostat measure. The evaluators suggested revisiting the billing analysis provided by the evaluators when additional self-installed incentives are processed.* Idaho Power will continue to use the most recently acknowledged RTF workbook at the time of program planning for the following year. The RTF recently updated the connected thermostat workbook in January 2022 and reduced the savings for self-installed thermostats from a simple average of 718 kWh to 295 kWh. These revised savings are more closely aligned to the savings the evaluators found in the billing analysis. In 2023, Idaho Power will determine how the program will need to be modified in the future to address the lower savings from the self-installed smart thermostats.

### 2023 Plans

Idaho Power will continue to provide program training to existing and prospective contractors to assist them in meeting program requirements and further their product knowledge.

Training remains an important part of the program because it creates the opportunity to invite additional contractors into the program, is a refresher for contractors already participating in the program, and helps them increase their customers' participation while improving the contractors' work quality and program compliance.

Idaho Power's primary goals in 2023 are to develop contractors currently in the program while adding new contractors. To meet these goals, the program specialist will frequently interact with contractors in 2023 to discuss the program.

The 2023 marketing strategy will include bill inserts, direct-mail, social media, digital and search advertising, and email marketing to promote individual measures as well as the overall program.

## Home Energy Audit

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 425 | 37 |
| | Energy Savings (kWh) | 28,350 | 3,768 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $184,650 | $70,448 |
| | Oregon Energy Efficiency Rider | $0 | $0 |
| | Idaho Power Funds | $208 | $0 |
| | Total Program Costs—All Sources | $184,858 | $70,448 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.771 | $2.173 |
| | Total Resource Levelized Cost ($/kWh) | $1.000 | $2.328 |
| **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 energy efficiency measures are appropriate. 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 feet [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 multifamily 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.

### Program Activities

Two home performance specialist companies served the program in 2022 and completed 425 energy audits. The number and percentage of audited homes per heating fuel type are listed in Table 12.

**Table 12. Number and percentage of audited homes per heating fuel type**

| Fuel Type | Number of Homes | Percent |
|---|---|---|
| Electric | 168 | 39.53% |
| Natural Gas | 237 | 55.76% |
| Oil | 2 | 0.47% |
| Pellets | 7 | 1.65% |
| Propane | 7 | 1.65% |
| Wood | 4 | 0.94% |

Quality assurance (QA) for the program has been suspended since 2020 due to COVID-19 restrictions and the ramp-up time to complete projects in the pipeline as a result. The QA for 2022 projects will occur in 2023, and Idaho Power is exploring the potential to transition to a survey format to both work through the pipeline of QAs and reduce program costs.

### Marketing Activities

To allow contractors to work through the long waitlist of interested customers that was created when in-home work was suspended in 2020 and 2021, Home Energy Audit marketing was limited in 2022.

Although there was still a waitlist throughout 2022, a bill insert was sent to 295,109 residential customers in July to help maintain program visibility. Website updates were made throughout the year to keep program details up to date.

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, 19.81%; family member or friend, 14.45%; Idaho Power employee, 13.29%; social media, 3.50%; other, 47.78%; did not reply, 1.17%.

### 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 use the traditional cost-effectiveness tests.

For the items installed directly in the homes, Idaho Power used the RTF savings for direct-install lightbulbs, which range from 4.73 to 14.21 kWh per year. This was a slight change over the 2021 lightbulb savings, which ranged from 4.68 to 17.59 kWh per year depending on lightbulb type and installation location.

In Idaho Power's *Energy Efficiency Potential Study*, it is estimated that pipe wraps save 76 kWh per year. Savings for pipe wrap are counted for homes with electric water heaters.

While Idaho Power does not calculate a cost-effectiveness ratio for the Home Energy Audit program, the savings benefits and costs associated with direct-install measures have been included in the sector and portfolio cost-effectiveness. Idaho Power also converted the 76 kWh of pipe wrap savings to 2.59 therms and those gas savings are included in the sector and portfolio cost-effectiveness as non-energy benefits.

### 2023 Plans

The program will be lightly marketed in 2023 while contractors continue to work through the waitlist. Once most customers have been served, Idaho Power will resume 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.

## *Home Energy Report Program*

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 104,826 | 115,153 |
| Energy Savings (kWh)* | 20,643,379 | 15,929,074 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $964,709 | $970,197 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $82 | $0 |
| Total Program Costs—All Sources | $964,791 | $970,197 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.044 | $0.057 |
| Total Resource Levelized Cost ($/kWh) | $0.044 | $0.057 |
| **Benefit/Cost Ratios**** | | |
| Utility Benefit/Cost Ratio | 0.71 | 0.57 |
| Total Resource Benefit/Cost Ratio | 0.79 | 0.62 |

*2021 reported savings of 16,767,446 kWh discounted by 5% to account for potential double-counting of savings from other programs. 2022 reported savings of 20,734,611 kWh discounted by 0.44% based on evaluated double-counting estimate

**Home Energy Report Program cost-effectiveness also calculated on a program life-cycle basis to account for savings persistence once treatment ends. The program has a life cycle UCT and TRC of 1.17 and 1.29, respectively.

### Description

The objective of the HER Program is to encourage customers to engage with their home's electricity use with a goal to produce average annual behavioral savings of 1 to 3%. The program also promotes customer use of online tools and participation in other energy efficiency programs. Idaho Power works with a third-party contractor to operate the program.

Participants receive periodic reports 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 by completing a statistical comparison of the energy used by customers who receive the reports against the energy used by a control group. Since the savings estimates rely on the integrity of the experimental design, participants in both the treatment (those receiving reports) and the control group are selected through a process of randomization.

### Program Activities

In 2022, all HER Program participants received quarterly reports in the months of February, May, August, and November.

In addition to showing participants how their energy compared relative to similar homes, each quarterly report delivered in 2022 addressed weather-related usage, as appropriate, along with other tips related to appliances, lighting, and always-on devices. The February reports recommended either ways to reduce electric heating costs or ways to cut energy costs associated with laundry and small kitchen appliances. In May, customers with significant A/C use during the previous summer received tips to reduce upcoming cooling bills while others learned about energy audits. The August reports were, once again, segmented between participants with significant A/C use and those whose energy use was less affected by weather. In November, customers with electric space heating received information regarding their previous winter's use along with heating tips while the remaining customers were divided into those using electric hot water heaters and those who did not.

In an effort to increase customer engagement and program savings, Idaho Power began sending email reports (eHER), in addition to paper reports, to participants for whom Idaho Power had an email address on file. Over 52,000 eHERs were delivered in August, compared to just 53 in May. The open rate was high (49%), and the call-in rate remained low. Following the August reports, 185 participants permanently switched to email only delivery.

In 2022, as in 2021, the savings results for the pilot participants identified as electric heating customers were not statistically significant as stand-alone cohorts; however, these participants did contribute to the overall program savings. The participants joining the program in 2020 once again saw increases in both their savings percentage and kWh savings per customer, increasing from 0.98% to 1.35% and from 144.28 kWh to 206.61 kWh, respectively. On average, the combined group of active participants used an average of 200.74 fewer kWh per home than their control group counterparts. When viewed in aggregate, the estimated savings for all program participants was about 1.31% below their respective control groups, for a total reported savings of 20,474,995 kWh. The small group of customers who received their last report in February of 2020 continued to demonstrate persistent savings. With their residual savings included, total 2022 reported program savings came to 20,734,611 kWh. On average, program participants are providing savings at between 56 to 267 kWh annually per home.

Idaho Power's customer solutions advisors responded to 409 HER Program-related phone calls during the year. Given that 505,735 reports were delivered, this represents a call rate of just under 0.08%. The participant-driven opt-out rate was down from 0.17% in 2021 to 0.08% in 2022—significantly lower than the industry average of 1%. Overall attrition in 2022 was 6.92%—down slightly from 7.82% in 2021 (includes opt-outs, move-outs, etc.).

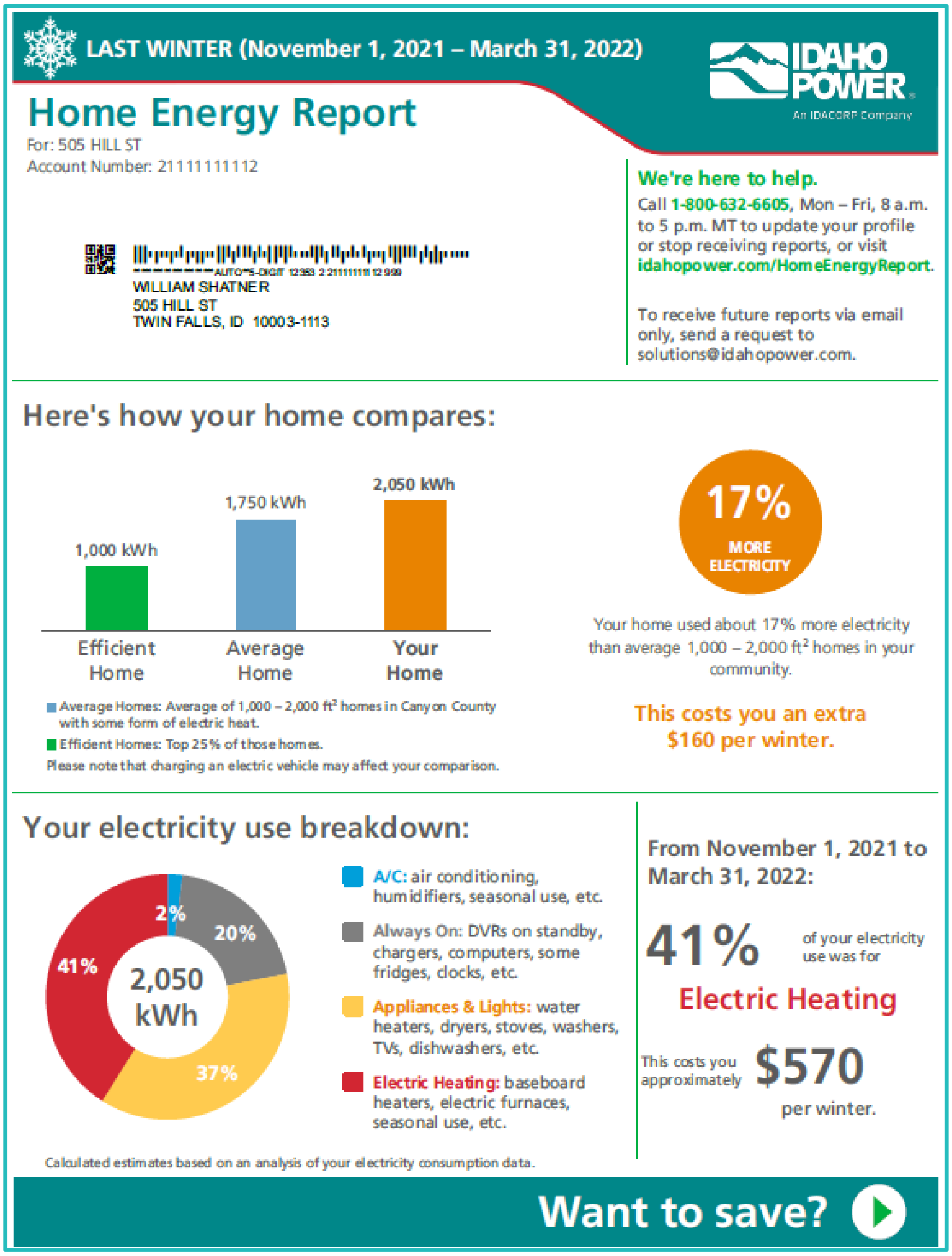



**Figure 18.** **Page 1 of a sample *Home Energy Report***

## Marketing Activities

Because the HER Program is based on a randomized control trial (RCT) 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 (i.e., Home Energy Audits, H&CE Program, and ENERGY STAR® lighting), as well as Account Alerts and My Account.

### Cost-Effectiveness

HER Program savings are calculated each year using measured usage of the customers receiving the reports relative to a statistically similar control group that does not receive the reports. Due to the potential of double-counting savings from other programs, Idaho Power discounts the HER Program savings of 20,734,611 kWh by 0.44% to report savings of 20,643,379 kWh. This percentage was reviewed as part of the 2022 impact evaluation. Based on the reported savings of 20,643 MWh, the UCT and TRC for the program are 0.71 and 0.79, respectively, for 2022. If the amount incurred for the 2022 evaluation was removed from the program's cost-effectiveness, the UCT would be 0.74, while the TRC would be 0.81.

Due to the continuous nature of the HER Program with costs and savings extending over numerous years for the same participants, a program life cost-effectiveness is used to understand the cost-effectiveness of the program as a whole. The analysis uses 2020 as the start year and assumes the program continues to send reports until the current contract ends in 2023. Savings per participant decrease at 20% per year from 2024 through 2026, at which point it is assumed the treatment no longer impacts the participants. Total participation also declines at 10% per year, which is the approximate observed annual attrition for the program. The life-time analysis has been updated to incorporate the 2022 program performance and updated 2023 savings projections from the third party. In late 2022, the IPUC and the OPUC formally acknowledged Idaho Power's *2021 IRP*. The demand-side management avoided costs from the *2021 IRP* are used to provide the monetary value for the energy savings in 2023 and beyond.

In February 2022, the RTF proposed guidelines for reviewing cost-effectiveness for behavioral programs. The company reviewed these guidelines and incorporated the concepts into the lifetime cost-effectiveness analysis. This lifetime analysis calculates UCT and TRC ratios of 1.17 and 1.29, respectively.

For more detailed information about the cost-effectiveness savings and assumptions, see Supplement 1: *Cost-Effectiveness.*

### Evaluations

In 2022, Idaho Power contracted a third-party evaluator to conduct an impact evaluation for the HER Program. The evaluation report for the HER Program was completed in September 2022. See *Supplement 2: Evaluation* for the complete report.

Recommendations were as follows:

*The evaluators recommend that Idaho Power and the implementer continue to prioritize the validity of each treatment and control group in order to maintain ability to estimate program savings. Previous changes throughout the program have resulted in maintenance of group validity due to additional steps relating to randomization, validity checks, and prioritization of* *statistical validity. The evaluators recommend IPC continue such efforts to ensure future program savings are evaluable and quantifiable*. Idaho Power and the implementer are aware of the complexity involved in the various control and treatment groups established during the pilot program and 2020 expansion and will continue to maintain the validity of each group according to industry best practices as established by the National Renewable Energy Laboratory's (NREL) Behavioral Programs Guide.

*Although the pilot phase of the program indicated that low to medium annual energy users displayed low propensity for energy savings, the evaluators found that these users (group T5) have displayed high persistence savings in recent years. Therefore, the evaluators recommend that Idaho Power allow customers with low to medium annual energy use to be eligible for participation in the program for any and all future group expansions*. At present, the company does not have plans to expand the program; however, Idaho Power will closely monitor the persistent savings for T5 and use those findings to inform decisions surrounding any future expansion.

*The evaluators recommend that Idaho Power continue to include customers that have converted from I01 rate schedule (general residential rate) to I06 rate schedule (customer generation rate) in the T1 through T6 groups and refrain from reallocating them to another treatment group. This will ensure that all legacy groups remain statistically valid and evaluable.* Idaho Power will continue to include I06 customers in their original T1/C1 through T6/C6 groups for evaluation purposes. When a HER participant transitions from the I01 to the I06 rate schedule, however, quarterly HERs will be discontinued as the home comparison no longer applies. This is consistent with current practice.

*The evaluators recommend that if a group is designed for the program in the future, that the lack of benchmarking characteristics is not used as a prerequisite for participation. This will ensure that the maximum number of customers are eligible for the Home Energy Report Program and therefore the program retains higher potential for total program energy savings.* Idaho Power will take this recommendation under consideration. The delivery of accurate and useful information is critical to a positive customer experience. Further, the implementer has requirements regarding adequately sized benchmark groups. If a future expansion occurs, Idaho Power will consult industry best practices and confer with the selected implementer, as well as other stakeholders.

### 2023 Plans

Idaho Power plans to 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 high A/C use or winter heating will also receive seasonal reports in either May or November, as appropriate.

As *Home Energy Reports* delivery is slated to end at the conclusion of 2023 under the current contract, Idaho Power will actively review the program’s cost-effectiveness, overall savings, and customer experience with an eye to selecting the best option(s) going forward.

## Multifamily Energy Savings Program

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Projects (units [buildings]) | 97 [3] | 0 |
| Energy Savings (kWh) | 41,959 | 0 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $32,634 | $65,525 |
| Oregon Energy Efficiency Rider | $1,474 | $3,449 |
| Idaho Power Funds | $72 | $0 |
| Total Program Costs—All Sources | $34,181 | $68,973 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.096 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.096 | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.49 | n/a |
| Total Resource Benefit/Cost Ratio | 0.68 | n/a |

### Description

The Multifamily Energy Savings Program provides for the direct installation of energy-saving products in multifamily 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 multifamily dwelling as a building consisting of five or more rental units. The products installed include the following: ENERGY STAR® LED lightbulbs, high-efficiency thermostatic shower valve (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 the program becoming not cost-effective and with the support of EEAG, the program was closed December 31, 2022. Before its closing, three direct-installation projects were completed in 2022. One each in the South–East, Canyon–West, and Capital regions for a combined total of 92 units and five common-area spaces.

### 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 2022. 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 April, the program specialist participated in the Idaho Apartment Association Conference and Trade Show to market the program to property owners and managers; Idaho Power placed a print ad in the trade show program

### Cost-Effectiveness

The UCT and TRC of the program are 0.49 and 0.68, respectively.

Due to the reduction of savings for the deemed measure options, the program in its current format is unable to remain cost-effective going forward. The RTF is the source of savings for many of the measures in the program. Based on the RTF version 9.4 lighting workbook, these savings now range between 4.73 to 13.81 kWh. To improve the accuracy of the data being collected, Idaho Power modified the installation worksheets. For lightbulbs installed in interior locations, Idaho Power had previously used a simple blend of savings for high- and moderate-use direct-install savings. With the updated savings worksheets, Idaho Power is able to directly assign the appropriate RTF direct-install savings. Additionally, some lightbulbs were installed in common areas, such as laundry rooms, hallways, and stairways. The updated worksheet was used to calculate the lighting savings for each install based on information around the existing lamp and the location of the installation. However, there are still challenges related to the other direct-install items with the company no longer able to claim savings for faucet aerators and the integrated showerhead with the TSV claiming only 50 kWh of annual savings.

Idaho Power shared these challenges with EEAG in 2021 and 2022. The company held a small subcommittee meeting in early 2022 to discuss the savings assumptions around the program and alternatives to the current direct-install retrofit model. The company was directed to reach out to the ETO to learn more about their multifamily program. ETO faced similar cost-effectiveness challenges with their direct-install multifamily program and suspended it in 2020. Based on the inability to run the direct-install program cost-effectively, Idaho Power announced to EEAG its intent to close the program in 2022. A prescriptive-based incentive program is being explored as an alternative cost-effective option for customers.

For more detailed information about the cost-effectiveness savings and assumptions, see Supplement 1: *Cost-Effectiveness.*

### 2023 Plans

Due to the closing of the program as of December 31, 2022, there are no activities planned for 2023, however, Idaho Power continues to pursue alternative program options for multifamily residences and believes it will have some type of new offering available in 2023.

## Oregon Residential Weatherization

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (audits/projects) | 7 | 0 |
| | Energy Savings (kWh) | 0 | 0 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $0 | $0 |
| | Oregon Energy Efficiency Rider | $8,825 | $4,595 |
| | Idaho Power Funds | $0 | $0 |
| | Total Program Costs—All Sources | $8,825 | $4,595 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/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

Seven audits were completed in 2022. None of the audit customers chose to pursue energy efficiency upgrades.

### Marketing Activities

In October, Idaho Power sent 10,336 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 7, 15, 25, and 30 years.

### 2023 Plans

Idaho Power will continue to market the program to customers with a bill insert/brochure.

## Rebate Advantage

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 97 | 88 |
| Energy Savings (kWh) | 255,541 | 235,004 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $157,746 | $164,243 |
| Oregon Energy Efficiency Rider | $9,762 | $8,950 |
| Idaho Power Funds | $115 | $0 |
| Total Program Costs—All Sources | $167,622 | $173,193 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.043 | $0.046 |
| Total Resource Levelized Cost ($/kWh) | $0.104 | $0.088 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.18 | 1.13 |
| Total Resource Benefit/Cost Ratio | 0.54 | 0.66 |

### 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. 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 Housing 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 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, NEEM+ delivers the highest possible energy savings and the highest level of overall comfort. These homes are built to specifications tailored to the Northwest climate.

### Program Activities

In 2022, for each home sold under this program, the residential customer incentive was $1,000 and the sales staff incentive was $200. Idaho Power paid 97 incentives on new manufactured homes, which accounted for 255,541 annual kWh savings. This included 91 homes sited in Idaho and six sited in Oregon. Of the 97 homes in the program, 25 were NEEM+, 61 were ENERGY STAR, and 11 were Eco-Rated.

### Marketing Activities

Idaho Power continued to support manufactured home dealerships by providing them with program marketing collateral.

In April and October, Idaho Power promoted the Rebate Advantage program with a bill insert sent to 306,888 and 298,681 customers, respectively. The insert had information about the potential energy and cost savings and referred customers to the program website.

In July, the company ran programmatic display ads that garnered 661,299 impressions and 463 clicks through to the website.

In the September issue of Idaho Power's *Get Your Home Ready for Fall* all-customer energy efficiency tips email, the Rebate Advantage program was featured in a digital banner ad. When clicked, it would take customers to the Rebate Advantage web page.

### Cost-Effectiveness

The UCT and TRC for the program are 1.18 and 0.54, respectively.

In 2022, Idaho Power used the same savings and assumptions source as were used in 2021. However, the number of NEEM 2.0 certified homes increased from 13 homes in 2021 to 25 homes in 2022. Manufactured homes certified under NEEM have higher savings than ENERGY STAR certified manufactured homes and are more expensive. This accounts for the slight increase in UCT and decrease in TRC as compared to 2021.

For detailed information for all measures within the Rebate Advantage program, see *Supplement 1: Cost-Effectiveness*.

### 2023 Plans

Idaho Power plans to review the cost-effectiveness and feasibility of the updated Housing and Urban Development (HUD)/ENERGY STAR v3.0 manufactured homes code that goes into effect on May 31, 2023, in conjunction with NEEM and NEEA.

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 Program

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 109 | 90 |
| | Energy Savings (kWh) | 337,562 | 389,748 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $236,962 | $246,245 |
| | Oregon Energy Efficiency Rider | -$1,356* | $1,356 |
| | Idaho Power Funds | $126 | $0 |
| | Total Program Costs—All Sources | $235,732 | $247,600 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.045 | $0.039 |
| | Total Resource Levelized Cost ($/kWh) | $0.110 | $0.082 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 1.45 | 1.64 |
| | Total Resource Benefit/Cost Ratio | 0.84 | 0.99 |

*2021 Oregon activity of $1,356 was reversed and charged to the Idaho Rider in the first quarter of 2022.

### Description

The Residential New Construction Program launched in March 2018 as a pilot, replacing the ENERGY STAR® Homes Northwest Program, and transitioned to a regular program in 2021. The Residential New Construction 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 (REM) 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 NEEA-maintained AXIS database. This data is used to determine the energy savings and the percent above code information needed to certify the home.

### Program Activities

Participating residential builders who built homes at least 10% above the standard state energy code, as determined by the REM/Rate energy modeling software and AXIS database output, were incentivized as follows:

- 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

In 2022, the company paid incentives for 109 newly constructed energy-efficient homes in Idaho, and the homes accounted for 337,562 kWh of energy savings.

Idaho Power continued its contract with Washington State University Energy Program to perform both file and field QA services on home energy ratings performed by the program raters. The university's contract also includes new rater training/on-boarding as well as working with current rater technical problems/issues.

### Marketing Activities

Idaho Power participated in the Snake River Valley Building Contractors Association (SRVBCA) and the Building Contractors Association of Southwestern Idaho (BCASWI) Builders' Expos and sent marketing materials to the winter and fall Idaho Building Contractors Association (IBCA) Board Meetings.

Idaho Power supported 2022 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 April construction issue of the *Idaho Business Review* publication. 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 305,714 Idaho customers in May to promote the program.

The program brochure was left at the City of Boise permitting office as a hard copy handout.

### Cost-Effectiveness

The savings for the 109 energy-modeled homes average approximately 3,097 kWh per home depending on which efficiency upgrades were included, a decrease over the average energy-modeled savings of 4,331 kWh per home in 2021. The decrease was largely due to a couple of factors: a lower percentage of homes built in 2022 (30%) were built 20% or more above code, relative to homes built in 2021 (63%); and a lower percentage of homes built in 2022 were detached single-family homes (8%), relative to homes built in 2021 (33%).

Single-family homes tend to have larger savings when compared to attached townhomes and condos.

While savings are custom calculated for each of the 109 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 non-energy benefits (NEB).

The UCT and TRC ratios for the program are 1.45 and 0.84, respectively.

### 2023 Plans

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 2023. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Social media and other advertising will be considered based on past effectiveness.

## Shade Tree Project

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (trees) | 1,874 | 2,970 |
| Energy Savings (kWh)* | 39,595 | 44,173 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $128,673 | $184,680 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $183 | $0 |
| Total Program Costs—All Sources | $128,856 | $184,680 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.218 | $0.269 |
| Total Resource Levelized Cost ($/kWh) | $0.218 | $0.269 |
| **Benefit/Cost Ratios*** | | |
| Utility Benefit/Cost Ratio | 1.02 | 1.07 |
| Total Resource Benefit/Cost Ratio | 1.21 | 1.21 |

* Incremental savings for trees planted between 2013–2018 not claimed in previous years.

### 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 or have trees delivered to their doors. 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 pick-up 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 College of Southern Idaho (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.

**Figure 19. Shade Tree Project pick-up event**

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. Of the trees planted in 2022, it is estimated that each tree will save approximately 28 kWh per year by 2032 and 44 kWh per year by 2042. The estimated savings for each tree is adjusted to reflect the estimated survivorship of the tree.

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.

**Shade Tree Project**

**Is a shade tree right for your home?**

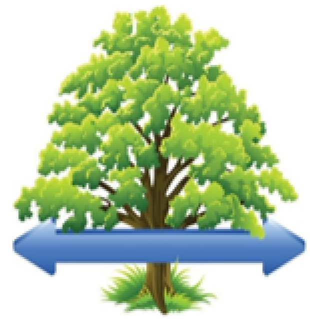
The free shade tree offer is open to Idaho Power residential customers in select counties. You must have the legal right to plant trees on your property and have enough space for a large, mature tree. There is a **limit** of **two trees per address for the life of the program.** Visit idahopower.com/shadetree for complete program details.

**Is there enough space on the west side of your property for a large shade tree?**

Once mature, the trees offered through this program will reach a height between 40 to 80 feet, with a canopy spread of 15 to 80 feet or more.

For the most summer energy savings, follow these tips:

- Plant on the west side of your home.
- Plant close enough to your home so the tree will provide the shade you need. However, to prevent branches from impacting your home, plant the tree about half the distance of the mature canopy width from your home.
- Ensure trees planted near streets comply with local ordinances. Generally, trees must be about 5 feet from streets and 40 feet from corners.



Canopy Spread

**Figure 20. Excerpt from spring direct-mail letter**

## Program Activities

While preparing for the 2022 season, it was not known if COVID-19 might impact in-person pick up events as it had in 2020 and 2021. The decision was made to offer hybrid events in 2022, which would allow customers to choose to receive their trees at an in-person event or have their trees shipped directly to their home. By offering hybrid events, Idaho Power was able to limit the number of people coming to collect their trees and ensure that the events were held in a safe manner should COVID-19 social distancing protocols need to be enforced. It also allowed an option for those customers that might not feel comfortable attending an in-person offering to still participate and receive their free trees.

The spring offering was made available to those customers that live in the Treasure Valley and the fall offering was available for those customers that reside in the Magic Valley. For each event, Idaho Power offered 500 3-gallon trees to be picked up at an in-person event and 500 1-gallon trees to be shipped directly to customers homes. Idaho Power collaborated with the Arbor Day Foundation to provide and ship the delivery trees. After the fall offering, there were over 100 trees that had not been reserved or were unclaimed. A small, impromptu offering in November was made available to customers in the Treasure Valley during which 47 of the leftover trees were claimed.

Idaho Power continues to track the program data in the DSM database. The database is also used to screen applicants during enrollment to determine whether participants meet the eligibility requirements for the project, such as residential status within the eligible counties. Participation in the program remains two trees per address for the life of the program.

### Marketing Activities

At the start of both the spring and fall campaigns, the company sent direct-mail letters to select customers, explaining the benefits of shade trees and encouraging program enrollments.

In spring 2022, Idaho Power sent two "enrollment open" emails encouraging customers in the Treasure Valley to sign up for trees; for those who chose the delivery option, Idaho Power sent "get ready" emails that included tree care tips and links to educational resources, and for those who chose the pick-up option, Idaho Power sent reminder emails that included pick-up event details and links to tree care resources. Idaho Power did the same for fall enrollment, except the emails were sent to Magic Valley and Wood River Valley customers. Due to slow enrollments in the fall campaign, Idaho Power sent additional emails after deciding to open enrollment to Ada County customers. To help with slow enrollment during the fall campaign, the program was promoted on Facebook and Twitter, and described in *News Briefs*, sent to regional news outlets to spread the word about the available trees.


**Figure 21. Shade Tree Project social media post**

### Cost-Effectiveness

For the Shade Tree Project, Idaho Power uses 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 software tool, i-Tree, estimates these benefits for years 5, 10, 15, and 20 after the tree planting year. However, the savings estimates assume each tree is planted as planned and does not consider survivorship. Idaho Power contracted with a third party to develop a model to calculate average values per tree using the tool data and calculated a realization rate based on the survival rate. Unlike traditional energy-savings measures in which the annual savings remain flat throughout the measure life and only first-year savings are reported, the savings for trees grow as the tree grows when using the realization rate based on survival. The calculator was used to estimate the 39,595 kWh of incremental claimable savings in 2022 for the trees planted between 2013 and 2018.

The cost-effectiveness for the program is based on the modeled savings for the trees distributed in 2022 and costs incurred during 2022. Of the tree distributed in 2022, 843 were distributed at in-person events and 1,031 were delivered directly to customers by mail. The trees delivered through the mail are estimated to be approximately one year younger than the trees distributed at the in-person events, which the calculator was based on. To adjust for this, the year the company could begin claiming savings was pushed out a year, thus the trees delivered by mail in 2022 will begin saving 17,656 kWh in 2027 while the trees distributed in person will begin saving 8,486 kWh in 2026 and 9,026 kWh in 2027. The cost-effectiveness calculations also include a NTG factor of 124%, which accounts for the spillover associated with the trees shading a neighboring home as well as various non-energy impacts related to the improved air quality, avoided stormwater runoff, and winter heating detriment. It is estimated that these trees will save 80,521 kWh in 2062. Based on the model, the project has a UCT of 1.02 and a TRC ratio of 1.21.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness.*

### Customer Satisfaction

After each offering, a survey was emailed to participants. The survey asked questions related to the program marketing, tree-planting education, and participation experience with the enrollment and tree delivery processes. Results are compared, offering to offering, to look for trends to ensure the program processes are still working to identify opportunities for improvement. Because this was Idaho Power's first year shipping the trees directly to customers, Idaho Power is also comparing customer satisfaction results from participants who picked up trees at in-person events in the past. Data is also collected about where and when the participant planted the tree. This data will be used by Idaho Power to refine energy-saving estimates.

In total, the survey was sent to 970 Shade Tree Project participants and 362 responses were received, for a response rate of 37%. Some highlights included the following:

- Almost 45% of respondents heard about the program from an Idaho Power email, and over 29% learned of the program from a friend or relative.
- Almost 79% of respondents were "very satisfied" with the information they received on the planting and care of their shade tree while over 17% of respondents were "somewhat satisfied."
- Participants were asked how much they would agree or disagree they would recommend the project to a friend. Nearly 91% of respondents said they "strongly agree," and over 7% said they "somewhat agree."
- Participants were asked how much they would agree or disagree they were satisfied with the overall experience with the Shade Tree Project. Almost 81% of respondents indicated they "strongly agree," and nearly 15% "somewhat agree" they were satisfied.

View the complete survey results in *Supplement 2: Evaluation*.

### 2023 Plans

Idaho Power plans to continue the Shade Tree Project in 2023, with the spring offering to customers in the Portneuf Valley and the fall event to customers in the Treasure Valley. Due to the general reduced satisfaction from direct-mail recipients and the easing of concerns over COVID-19 restrictions, the direct-mail option will be discontinued in 2023 and only in-person events will be held. The enrollment process will remain the same, using the Arbor Day Foundation enrollment tool.

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 explore the opportunity to be promoted in the *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 email for the 2023 offerings. Idaho Power will continue to leverage allied interest groups and use social media and boosted Facebook posts if enrollment response rates decline.

## Weatherization Assistance for Qualified Customers

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 147 | 162 |
| Energy Savings (kWh) | 272,647 | 291,105 |
| 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 | $1,281,495 | $1,186,839 |
| Total Program Costs—All Sources* | $1,281,495 | $1,186,839 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.338 | $0.254 |
| Total Resource Levelized Cost ($/kWh) | $0.535 | $0.374 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.17 | 0.19 |
| Total Resource Benefit/Cost Ratio | 0.32 | 0.31 |

* 2021 and 2022 Total Program Costs include 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 and 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. Regional 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 electrically heated buildings.

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 verifies a portion of the homes weatherized under the WAQC program. This is done through two methods. The first method uses a state monitoring process where either an independent quality-control inspector or trained peers ensure measures were installed to DOE and state WAP specifications. Utility representatives, weatherization personnel from the CAP agencies, and CAPAI, review homes weatherized by each of the CAP agencies. In 2022, eight Idaho Power funded homes were chosen for review.

For the second method, Idaho Power contracts with two companies that employ building performance specialists to verify the installed measures. After verification, any required follow-up is done by CAP agency personnel. In 2022, six homes were verified by Idaho Power's home verifiers.

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 2022, Idaho Power made $2,083,519 available to Idaho CAP agencies. Of the funds provided, $934,615 were paid to Idaho CAP agencies, while $1,148,905 were accrued for future funding. This relatively large carry over was caused by supply chain limitations and labor shortages limiting the number of homes CAP agencies weatherized. Of the funds paid in 2022, $849,650 directly funded audits, energy efficiency measures, and health and safety measures for qualified customers' homes (production costs) in Idaho, and $84,965 funded administration costs to Idaho CAP agencies for those homes weatherized.

In 2022, Idaho Power funds provided for the weatherization of 147 homes and no non-profit buildings in Idaho. Table 13 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 13. WAQC activities and Idaho Power expenditures by agency and county in 2022**

| Agency/County | Number of Homes | Production Cost | Average Cost | Administration Payment to Agency | Total Payment |
|---|---|---|---|---|---|
| **Idaho Homes** | | | | | |
| EICAP | | | | | |
| Lemhi | 6 | $ 34,876 | $ 5,813 | $ 3,488 | $ 38,364 |
| **Agency Total** | **6** | **$ 34,876** | | **$ 3,488** | **$ 38,364** |
| EL ADA | | | | | |
| Ada | 72 | 422,557 | 5,869 | 42,256 | 464,813 |
| Elmore | 8 | 52,174 | 6,522 | 5,217 | 57,391 |
| Owyhee | 10 | 65,230 | 6,523 | 6,523 | 71,754 |
| **Agency Total** | **90** | **$ 539,961** | | **$ 53,996** | **$ 593,957** |
| Metro Community Services | | | | | |
| Adams | 1 | 7,836 | 7,836 | 784 | 8,619 |
| Boise | 1 | 6,848 | 6,848 | 685 | 7,532 |
| Canyon | 19 | 97,333 | 5,123 | 9,733 | 107,066 |
| Gem | 2 | 15,374 | 7,687 | 1,537 | 16,911 |
| Payette | 4 | 29,365 | 7,341 | 2,936 | 32,301 |
| Valley | 2 | 13,725 | 6,863 | 1,373 | 15,098 |
| **Agency Total** | **29** | **$ 170,479** | | **$ 17,048** | **$ 187,527** |
| SCCAP | | | | | |
| Blaine | 1 | 8,634 | 8,634 | 863 | 9,498 |
| Cassia | 1 | 2,343 | 2,343 | 234 | 2,578 |
| Jerome | 4 | 18,113 | 4,528 | 1,811 | 19,924 |
| Lincoln | 2 | 9,045 | 4,523 | 905 | 9,950 |
| Twin Falls | 3 | 15,432 | 5,144 | 1,543 | 16,975 |
| **Agency Total** | **11** | **$ 53,567** | | **$ 5,357** | **$ 58,924** |
| SEICAA | | | | | |
| Bannock | 6 | 23,320 | 3,887 | 2,332 | 25,652 |
| Bingham | 2 | 7,487 | 3,744 | 749 | 8,236 |
| Power | 3 | 19,959 | 6,653 | 1,996 | 21,954 |
| **Agency Total** | **11** | **$ 50,766** | | **$ 5,077** | **$ 55,842** |
| **Total Idaho Homes** | **147** | **$ 849,650** | | **$ 84,965** | **$ 934,615** |
| Non-Profit Buildings | | | | | |
| **Total Non-Profit Buildings** | **0** | **$ 0** | **$ 0** | **$ 0** | **$ 0** |
| **Oregon Homes** | | | | | |
| CCNO—Baker | 0 | 0 | 0 | 0 | 0 |
| **Agency Total** | **0** | **0** | **0** | **$ 0** | **$ 0** |
| CINA—Malheur | 0 | 0 | 0 | 0 | 0 |
| **Agency Total** | **0** | **0** | **0** | **$ 0** | **$ 0** |
| **Total Oregon Homes** | **0** | **0** | **0** | **$ 0** | **$ 0** |
| **Total Program** | **147** | **$ 849,650** | | **$ 84,965** | **$ 934,615** |

Note: Dollars are rounded.

The base funding for Idaho CAP agencies is $1,212,534 annually, which does not include carry over 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 2022 agreement was $6,000. In 2022, Idaho CAP agencies had a combined average cost per home weatherized of $5,780.

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 2022 was $578. Not included in this report's tables are additional Idaho Power staff labor, marketing, and support costs for the WAQC program totaling just over $67,400 for 2022. 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 2022, $870,985 in unspent funds from 2021 were made available for expenditures in Idaho. Table 14 details the base funding and available funds from 2021, and the total amount of 2022 spending.

**Table 14. WAQC base funding and funds made available in 2022**

| Agency | 2022 Base | Available Funds from 2021 | Total 2022 Allotment | 2022 Spending |
|---|---|---|---|---|
| **Idaho** | | | | |
| EICAP | $ 12,788.00 | $ 25,576.00 | $ 38,364.00 | $ 38,364.00 |
| EL ADA | 568,479.00 | 87,969.13 | 656,448.13 | 593,957.27 |
| Metro Community Services | 302,259.00 | 217,540.54 | 519,799.54 | 187,527.15 |
| SCCAP | 167,405.00 | 217,334.22 | 384,739.22 | 58,924.24 |
| SEICAA | 111,603.00 | 193,174.13 | 304,777.13 | 55,842.06 |
| Non-profit buildings | 50,000.00 | 129,391.44 | 179,391.44 | 0 |
| **Idaho Total** | **$ 1,212,534.00** | **$ 870,985.46** | **$ 2,083,519.46** | **$ 934,614.72** |
| **Oregon** | | | | |
| CCNO | $ 6,750.00 | $ 3,375.00 | $ 10,125.00 | $ 0 |
| CINA | 38,250.00 | 19,125.00 | 57,375.00 | 0 |
| **Oregon Total** | **$ 45,000.00** | **$ 22,500.00** | **$ 67,500.00** | **$ 0** |

Because of supply chain issues and labor shortages, various weatherization department's production schedules were lower than normal, and less Idaho Power funding was spent in 2022. Unspent funding will be carried over to 2023.

#### *Weatherization Measures Installed*

Table 15 details home counts for which Idaho Power paid all or a portion of each measure's cost during 2022. 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, like 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 and 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 15. WAQC summary of measures installed in 2022**

| | Counts | Production Costs |
|---|---|---|
| **Idaho Homes** | | |
| Audit | 90 | $ 10,242 |
| Ceiling Insulation | 29 | 28,888 |
| LED lightbulbs | 22 | 901 |
| Doors | 60 | 50,133 |
| Ducts | 14 | 7,708 |
| Floor Insulation | 24 | 32,126 |
| Furnace Repair | 4 | 3,015 |
| HVAC Replacement | 119 | 558,891 |
| Health and Safety | 17 | 12,815 |
| Infiltration | 85 | 12,957 |
| Other | 0 | 0 |
| Pipes | 7 | 760 |
| Vents | 4 | 482 |
| Wall Insulation | 2 | 563 |
| Water Heater | 4 | 3,726 |
| Windows | 70 | 126,443 |
| **Total Idaho Homes** | | **$ 849,650** |

| | Counts | Production Costs |
|---|---|---|
| **Oregon Homes** | 0 | 0 |
| **Total Oregon Homes** | **0** | **0** |
| **Idaho Non-Profits** | 0 | 0 |
| **Total Idaho Non-Profit Measures** | **0** | **$ 0** |

Note: Dollars are rounded.

***Re-Weatherization***

Idaho Power identified a large increase in carry over funds to CAP agencies that had occurred due to a combination of COVID-19 in-home activity restrictions, supply chain limitations and labor shortages limiting the number of homes CAP agencies weatherized. In May 2022, with support from EEAG, Idaho Power filed a proposal (IPC-E-22-15) with the IPUC designed to address the increase by expanding eligibility for weatherization to include homes that had been weatherized within the last rolling 14-year period but that had not received HVAC upgrades. Because these homes are not eligible to receive federal funding for re-weatherization within a rolling 14-year period based on DOE guidelines, Idaho Power's proposal was to fund HVAC upgrades at 100% of the cost for these jobs. In November 2022, the IPUC approved the company's application in Order No. 35583. No homes in this category were completed before the end of the year.

### 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. Idaho Power regional energy advisors and EOEAs promote WAQC when working directly with customers in their communities, at fairs, senior centers, and during other presentations in their regions. The CAP agencies also promote the program through their outreach activities.

### Cost-Effectiveness

In 2022, WAQC program cost-effectiveness was 0.17 from the UCT perspective and 0.32 from the TRC perspective.

The savings values were updated in 2020 based on a billing analysis of program participants conducted by a third party; there were no changes to the values used for reporting from 2020 to 2022. Idaho Power plans to update this billing analysis in 2023.

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 tool to conduct the initial audit of the home. The EA5 tool is used to compare 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 2022 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 calculation removes the impacts of any accruals and reversals associated with unspent dollars carried over into the following year. In 2022, the amount carried over into 2023 was $277,919. By leaving this amount in the cost-effectiveness calculation, it would overstate expenses in 2022 while the subsequent reversal would understate expenses in 2023. Idaho Power will continue to work with EEAG, as well as the weatherization managers who oversee the weatherization work, to discuss ways to improve the program. For further details on the overall program cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

### 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 can ask the home verifiers more questions.

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 132 of 147 households weatherized by the program in 2022. Some highlights include the following:

- Over 48% of respondents learned of the program from a friend or relative, and almost 17% learned of the program from an agency flyer. Over 14% learned of the program from the Idaho Power website.
- Over 48% of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, almost 20% wanted to improve the comfort of their home, and almost 18% had concerns about their existing furnace.
- Over 23% reported they learned how air leaks affect energy usage, and almost 23% indicated they learned how to use energy wisely during the weatherization process.
- Over 15% of respondents said they learned how to program the new thermostat. Most respondents (over 98%) reported they were likely to change habits to save energy, and over 99% reported they have shared all the information about energy use with members of their household.
- Over 92% of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost all (99.12%) said they were "very satisfied" with the program.
- Over 19% of the respondents reported the habits they were most likely to change to save energy was turning the thermostat down in winter and up in the summer. Turning off lights when not in use was reported by over 19% of the respondents, and washing full loads of clothes was reported by over 15% 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*.

### 2023 Plans

In 2023, 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. Since the retirement of the Idaho state WAP energy audit tool (EA5) in late 2022, CAP agency personnel will invoice Idaho Power with a new job cost calculator starting in 2023. The job cost calculator will be filled with information from the new state audit tool, ECOS.

Idaho Power plans to continue to verify approximately 5% of the homes weatherized under the WAQC program via home-verification companies and the Idaho and Oregon state monitoring process.

In 2023, 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. The company will continue to work with CAPAI, CAP agencies, and IDHW to develop recommendations and ideas to help improve the program for customers with special needs.

In Idaho during 2023, Idaho Power expects to contribute the base amount plus available funds from 2022 of just under $1,148,905 to total $2,361,439 in weatherization measures and agency administration fees. Of this amount, approximately $229,391 will be provided in the non-profit pooled fund to weatherize buildings housing non-profit agencies that primarily serve qualified customers in Idaho, with an allowance for annual unused non-profit funds to be used toward additional residential weatherization projects.

The newly approved re-weatherization option will be implemented in 2023. A list of customers that received weatherization within a prior 14-year rolling period but did not receive HVAC system replacements are being provided to weatherization managers. From these lists, weatherization managers will contact customers and work with HVAC contractors to determine whether HVAC upgrades are warranted and identify the type of system that would work best in the qualified home. Based on Idaho state WAP guidelines, the HVAC contractor may replace the HVAC system of the previously weatherized home and have the completed home inspected by the entity that issues the permit. Re-weatherization jobs will be invoiced to Idaho Power separately from regular WAQC jobs and will be paid with funds from each CAP Agency's individual portion of the annual WAQC amount which includes carry over of unused funds from previous years. Re-weatherized homes will be reported in the company's annual DSM report as a portion of the individual WAQC report.

Idaho Power will continue to maintain the program content on its website and include it with other marketing collateral.

## Weatherization Solutions for Eligible Customers

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 27 | 7 |
| | Energy Savings (kWh) | 48,233 | 12,591 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $198,198 | $54,793 |
| | Oregon Energy Efficiency Rider | $0 | $0 |
| | Idaho Power Funds | $7,590 | $2,863 |
| | Total Program Costs—All Sources | $205,788 | $57,656 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.307 | $0.317 |
| | Total Resource Levelized Cost ($/kWh) | $0.307 | $0.317 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 0.15 | 0.15 |
| | Total Resource Benefit/Cost Ratio | 0.23 | 0.28 |

### 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 program also benefits certain customers on the state weatherization waiting list. When customer income overlaps both programs, this program may offer an earlier weatherization date than state WAP, 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 eligible. If the home is a rental, the landlord must agree to maintain the unit’s current rent for a minimum of one year, and to help fund a portion of the cost of weatherization. If the customer is eligible, an auditor inspects the home to determine which upgrades will save energy, improve indoor air quality, and/or provide health and safety 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 that 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

Due to extended COVID-19 labor shortages, some contractors continued to experience hardships hiring and training weatherization crew members resulting in lower production numbers in 2022. Contractors weatherized 27 Idaho homes for the program: two in CAP's eastern region, 23 in CAP's south-central region, and two in Idaho Power's Capital region. Of those 27 homes weatherized, 18 were single-family, seven were manufactured homes, and two were multi-family units. Contractors reported increased costs for materials and equipment from previous years.

Two independent companies performed random verifications of weatherized homes and visited with customers about the program. In 2022, seven homes were verified and of those verifications, one job required the Contractor to return to perform minor repairs.

### Marketing Activities

The program was not marketed in 2022 to allow contractors time to work through their existing waiting lists, which are a result of worker shortages, supply chain restrictions, and the high volume of WAQC applicants on regional CAP Agency waiting lists.

### Cost-Effectiveness

In 2022, the Weatherization Solutions for Eligible Customers program cost-effectiveness was 0.15 from the UCT perspective and 0.23 from the TRC perspective.

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. In 2023, Idaho Power plans to conduct a billing analysis of program participants to update the savings assumptions associated with the program.

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. Program participants 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 21 of 27 households weatherized by the program in 2022. Some highlights include the following:

- Over 21% of respondents learned of the program from a friend or relative, and another almost 11% learned of the program from a letter in the mail. Several people cited learning about the program through a bill stuffer.
- Over 63% of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, and over 21% wanted to improve the comfort of their home.
- Over 20% reported they learned how air leaks affect energy usage, and the same percentage indicated they learned how insulation affects energy usage.
- Over 19% of respondents said they learned how to use energy wisely. 100% reported they were very likely to change habits to save energy, and 100% reported they have shared all the information about energy use with members of their household.
- Over 84% 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.
- Almost 41% of the respondents reported the habit they were most likely to change was unplugging electrical equipment when not in use, and over 9% 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 and down in the winter was reported by almost 5% of the respondents 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*.

### 2023 Plans

It is anticipated that program activity may be lower than normal again in 2023 due to worker shortages, supply chain restrictions, and the high volume of WAQC applicants on regional CAP Agency waiting lists.

Idaho Power will update brochures as necessary to help spread the word about the program in all communities in 2023. If needed, additional marketing for the program may include bill inserts, emails, *News Briefs*, website updates, and ads 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 for Eligible Customers services.

# Commercial & Industrial Sector Overview

In 2022, Idaho Power's C&I sector consisted of 77,306 commercial, governmental, school, and small business customers. The number of customers increased by 1,284 or 1.7% versus 2021. 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 2022, the commercial sector represented 27% of Idaho Power's total retail annual electricity sales.

Industrial and special contract customers are Idaho Power's largest individual energy consumers. In 2022, there were 125 customers in this category, representing approximately 22.2% 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 16. Commercial/Industrial sector program summary, 2022**

| | | Total Cost | | Savings | |
|---|---|---|---|---|---|
| **Program** | **Participants** | **Utility** | **Resource** | **Annual Energy (kWh)** | **Peak Demand (MW)*** |
| **Demand Response** | | | | | |
| Flex Peak Program | 159 sites | $ 519,618 | $ 519,618 | | 24.5/30 |
| **Total** | | **$ 519,618** | **$ 519,618** | | **24.5/30** |
| **Energy Efficiency** | | | | | |
| CIEE | | | | | |
| Custom Projects | 106 projects | 8,919,927 | 25,715,468 | 56,157,060 | |
| Green Motors Initiative—Industrial | 9 motor rewinds | 0 | 3,424 | 19,851 | |
| New Construction | 88 projects | 2,780,507 | 3,641,930 | 27,615,777 | |
| Retrofits | 525 projects | 4,870,916 | 13,402,016 | 22,890,678 | |
| Commercial Energy-Saving Kits | 334 kits | 22,770 | 22,770 | 48,758 | |
| Small Business Direct Install | 680 projects | 1,345,429 | 1,345,429 | 3,228,365 | |
| **Total** | | **$ 17,939,548** | **$ 44,131,037** | **109,960,489** | |

**Notes:**

See Appendix 3 for notes on methodology and column definitions.

Totals may not add up due to rounding.

* Demand response program reductions are reported with 9.7% peak loss assumption. Maximum actual demand reduction/maximum demand capacity.

## *Commercial and Industrial DSM 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

(SEM) cohorts, 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. A Professional Assistance Incentive (PAI) is available for the architect or engineer on the project through this option.

**C&I Energy Efficiency—Retrofits.** This option offers prescriptive incentives for energy-saving retrofits to existing equipment or facilities.

**Green Motors Initiative (GMI).** Under the 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 commercial kits filled with products and tips to help businesses save energy. The commercial kit is assembled and delivered directly to Idaho Power's business customers by a third-party vendor.

**Flex Peak Program.** A demand response program that pays an incentive to C&I customers who voluntarily reduce energy use during periods of high energy demand or for other system needs.

**Small Business Direct Install (SBDI).** SBDI targets 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 less than 25,000 kWh annually. 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.

## *Marketing*

In 2022, Idaho Power continued to market the programs listed above, targeting the following customers: commercial, industrial, government, schools, small businesses, architects, engineers, and other design professionals.

### Bill Inserts

A bill insert highlighting how Idaho Power's incentives can save customers money was included in 33,030 business customer bills in March, and a version of the insert was included in 39,407 bills in July.

### Print and Digital Advertising

In 2022, the print ads focused on promoting offered incentives and their availability to businesses of all sizes. The company also continued to promote energy efficiency with messages around safe, reliable, affordable, and clean energy in select publications.

Print ads ran in the *Idaho Business Review* in April, May, August, September, October, and November. Also, ads 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 145,184 impressions and 18,086 clicks.

### Newsletters

Idaho Power produces a monthly newsletter called *Connections* that is distributed to all customers and covers a variety of topics. The February issue was dedicated to small-business-related energy efficiency topics, including the Zeppole energy efficiency story, energy-saving resources for small businesses, and the impact small businesses have at Idaho Power.

Idaho Power produces and distributes *Energy@Work*, a quarterly newsletter about Idaho Power company information and energy efficiency topics for business customers. In 2022, newsletters were delivered electronically.

- The spring issue was sent to 16,557 customers in March. The issue focused on the demand response program changes and energy efficiency incentives that benefited customers in Blackfoot and Sun Valley.
- The summer issue, sent to 16,995 customers in June, focused on celebrating dairy month, City of Boise and Lamb Weston receiving an incentive for their energy efficiency projects, and 2022 training opportunities.
- The fall issue was sent to 17,407 customers in September. The issue included a thank you to participants in the Flex Peak demand response program, an article about providing businesses with reliable and affordable energy, and information about the industrial Wastewater Energy Cohort and commercial ESKs.
- The winter issue was sent to 17,690 customers in December. The issue included articles about Idaho Power's mobile app that helps small businesses, Idaho Power support for Agropur's energy-saving projects, and workshops for school cohort participants.

### Airport Advertising

To reach business customers, Idaho Power continued to display two backlit ads throughout the airport in 2022. The ad promotes how Idaho Power helps power businesses and is displayed in the main concourse walkway for increased visibility. Additionally, 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 August through October. The company ran a total of 402 messages in Boise and Twin Falls, and 786 messages in Pocatello.

### Social Media

Idaho Power continued using regular LinkedIn posts focused on energy-saving tips, program details, incentives, and training opportunities. When appropriate, these messages were also shared on Idaho Power's Facebook and Twitter pages.

### 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.

These opportunities were available in 2022, after years of postponement due to the pandemic. Idaho Power produced checks and supported PR efforts for several companies, including City of Blackfoot, City of Ketchum, Micron, Lamb Weston, Power County Hospital, City of Twin Falls, Kuna Joint School District, Materne, Agropur, Ford Idaho Center, and Boise School District.

### Association and Event Sponsorships

Idaho Power's C&I Energy Efficiency Program typically sponsors a number of associations and events. In 2022, some of the events were back to an in-person format.

The company sponsored the BOMA Commercial Real Estate Symposium February 14–15 and placed an ad and article in the event program. During the event, a company executive was a speaker on a panel, slides were presented with key company facts that rotated on the screen before the event, and Idaho Power had a booth with materials promoting energy efficiency. Takeaway brochures were placed at each table.

Idaho Power remained a sponsor of the Idaho Business Review's Top Projects Awards held in October in Boise. The company logo was used throughout the event, an Idaho Power employee spoke during the event as a long-standing judge, and company materials were placed at the tables.

Idaho Power sponsored the Edison Electric Institute (EEI) National Accounts Workshop held in October in Indianapolis. Promotion included the company logo, a booth with brochures and materials, and program descriptions on the EEI online marketplace.

### *Customer Satisfaction*

Idaho Power conducts the *Burke Customer Relationship Survey* each year. In 2022, on a scale of zero to 10, small business survey respondents rated Idaho Power 8.04 regarding offering programs to help customers save energy, and 7.82 related to providing customers with information on how to save energy and money. Twelve percent of small business 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, 85% are "very" or "somewhat" satisfied with the program.

In 2022, on a scale of zero to 10, large C&I survey respondents rated Idaho Power 9.06 regarding offering programs to help customers save energy, and 8.73 related to providing customers with information on how to save energy and money. Thirty-eight percent of large C&I respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large C&I survey respondents who have participated in at least one Idaho Power energy efficiency program, 98% are "very" or "somewhat" satisfied with the program.

### *Training and Education*

In 2022, 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, email, and the *Energy@Work* newsletter.

During each training session, a program engineer gave an overview of the C&I Energy Efficiency Program incentives available to customers.

As part of the training and education outreach activity, Idaho Power collaborated with and supported stakeholders and organizations, such as Integrated Design Lab (IDL) and the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE). Using Idaho Power funding, 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 at various design and engineering firms, and offering the Energy Resource Library (ERL).

Idaho Power delivered six equivalent full-time days of live, online technical training sessions in 2022 at no cost to the customers over the course of 11 days. Topics included the following:

- HVAC System Testing for Energy Efficiency
- Motors and VFDs
- Fan System Training
- Chilled Water System and Cooling Towers
- Energy Management Systems
- Compressed Air Training

The level of participation in 2022 remained high, with 216 individuals signing up and 150 attending the technical sessions. Due to the virtual nature of the course delivery, 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 2022 was approximately $4,567 per class. Idaho Power surveyed customers to obtain feedback on the training program. After reviewing the results of the survey, Idaho Power plans to implement suggestions to continue providing valuable training to meet customers' needs.

Additionally, Idaho Power offered four live, online technical training sessions to industrial wastewater customers, and extended invitations to those outside of the cohort participants. Topics included the following:

- Water Energy Basics
- Wastewater Typical No-/Low-Cost Opportunities
- Pumps and Efficiency
- Activated Sludge Basics

Industrial wastewater trainings were attended by 50 participants. Cohort members and other operators were invited and offered continuing education units for industrial wastewater professionals. Each course is designed to study improved operation, quality, and energy performance for different systems.

Aside from the classes listed above, Idaho Power also partnered with the NEEC to administer a Building Operator Certification Level I Course that began in November 2021 and continued through May 2022. Idaho Power sponsored 17 customers who signed up for the training and paid $900 of the $1,895 tuition cost upon completion.

### Field Staff Activities

Energy efficiency opportunities continue to be an important factor for most businesses. Many of our large commercial customers have been approached to evaluate other creative solutions to manage their energy, such as installing solar coupled with batteries. The energy advisors have had many opportunities to help evaluate these solutions on behalf of customer requests and generally the least-cost option continues to be energy efficiency. Idaho Power's energy efficiency programs are designed to accommodate all possible efficiency opportunities, ranging from equipment improvements to a variety of business cohorts that offer support and ongoing training for a long-term, more sustainable approach to energy efficiency.

Idaho Power has trained friendly and engaged energy advisors in each region and while market uncertainty has slowed some projects, the energy advisors continue to support and influence participation. For a time during COVID-19, Idaho Power's energy advisors were performing most of their annual visits online or by phone. In general, the energy advisors returned to in-person site visits in 2022. They have, however, found that a combination of in-person and web meetings offers more customer flexibility. The company continued to offer online technical training to commercial building engineers, trade allies, and other stakeholders to help them be successful with the ongoing promotion of energy efficiency opportunities.

## Commercial and Industrial Energy Efficiency Program

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings*** | | |
| Participants (projects) | 728 | 1,021 |
| Energy Savings (kWh)** | 106,683,366 | 92,465,723 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source***** | | |
| Idaho Energy Efficiency Rider | $16,301,140 | $14,375,182 |
| Oregon Energy Efficiency Rider | $266,764 | $742,013 |
| Idaho Power Funds | $3,445 | $9,630 |
| Total Program Costs—All Sources | $16,571,349 | $15,126,824 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.017 |
| Total Resource Levelized Cost ($/kWh) | $0.043 | $0.043 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.86 | 2.86 |
| Total Resource Benefit/Cost Ratio | 1.33 | 1.46 |

*Metrics for each option (New Construction, Custom Projects, and Retrofits) are reported separately in the appendices and in *Supplement 1: Cost-Effectiveness*.

**2021 total includes 20,430 kWh of energy savings from four GMI projects. 2022 total includes 19,851 kWh of energy savings from 9 GMI projects.

***2021 and 2022 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.

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 2022 activities and results not already described in the C&I Sector Overview are described below.

#### *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 or energy management projects. Additionally, Idaho Power operates SEM cohorts under the Custom Projects option.

Incentives reduce customers' payback periods for custom modifications and promote energy-saving operations that might not otherwise be completed. The Custom Projects option also offers energy assessment services and customer training 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 provide or gather sufficient information to support the estimated energy-savings calculations, then pre-approves the project. Then, the customer moves forward with the project. In some cases, large, complex projects may take as long as two or more years to complete.

Once the project is completed, customers submit a payment application, and 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 final energy savings and the project costs are estimated.

On the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data verification (M&V) before and after project implementation to confirm energy savings are obtained and are within program guidelines. If changes in project scope take place, Idaho Power recalculates 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 into new construction, expansion, or major remodeling projects. Initiated in 2004, the New Construction option currently offers incentives for 33 energy-saving building and design features related to efficient lighting, lighting controls, building shell, HVAC equipment, HVAC controls, variable speed drives, refrigeration, compressed air equipment, appliances, and other equipment. A complete list of the measures offered through New Construction is included in *Supplement 1: Cost-Effectiveness*. The customer may otherwise lose savings opportunities for these types of projects. The new construction and major renovation project design and construction process often encompasses multiple calendar years. In addition to the customer incentive, a PAI is available to architects and/or engineers for supporting technical aspects and documentation of a project.

#### *Retrofits*

The Retrofits option is Idaho Power's prescriptive measure option for existing facilities that offers incentives to customers in Idaho and Oregon for a defined list of energy efficiency upgrade measures. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, food service equipment, and other commercial measures. A complete list of the measures offered through Retrofits is included in *Supplement 1: Cost-Effectiveness*.

### Program Activities—Custom Projects

The Custom Projects option provides incentives for both custom capital projects and energy-management projects.

Incentive levels for custom capital projects remained the same in 2022, at $0.18 per kWh of estimated kWh savings for one year, up to 70% of the project cost.

Idaho Power provides incentives for conducting pressurized, underground water leak assessments and fixing those leaks. The program reimburses $1,000 per five miles of pipe detected for a third-party leak assessment in addition to the standard capital project incentive of $0.18 per kWh of first-year savings for repair.

The energy management incentive of $0.025 per first-year kWh saved, up to 100% of the eligible costs (added in 2020), also remained the same in 2022. Compared to typical custom capital projects, energy management projects tend to have the following:

- A shorter measure life and a much lower cost
- O&M changes that save energy without interrupting the customer's service or product
- Cost-effective energy savings from measures rooted in low-cost or no-cost O&M improvements.

Compressed air system leak repairs are eligible under the energy management incentive at $0.025 per kWh estimated to be saved in one year up to 100% of project cost. Customers can use their own instrumentation or work with one of Idaho Power's third-party consultants to identify leaks. Energy savings achieved from fixing leaks can be quantified, and project costs are calculated by factoring in the material cost to fix the leaks as well as any labor requirements.

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 is currently contracted with six firms to provide scoping assessments and general energy efficiency engineering support services through 2025. Two of the firms are focused on energy modeling to support cohorts and other energy management offerings. The other four firms provide a wide array of engineering services, including scoping assessments, detailed assessments, energy modeling, and various SEM programs.

The Custom Projects option had a successful year with a total of 106 completed projects (5 of which were in Oregon) and achieved energy savings of 56,157 MWh (Table 16), which is a 5% increase compared to 2021. COVID-19 impacts continued to present challenges for projects in 2022, and many projects were slowed down by materials and labor issues.

Idaho Power also received 108 new applications in 2022, representing a potential of 64,775 MWh of savings on future projects.

In 2022, Idaho Power contractors completed 26 scoping assessments on behalf of Idaho Power customers. These assessments identified over 28,984 MWh of savings potential and will be used to promote future projects.

**Table 17. Custom Projects annual energy savings by primary option measure, 2022**

| Option Summary by Measure | Number of Projects | kWh Saved |
|---|---|---|
| Compressed Air | 11 | 8,111,646 |
| Controls | 1 | 152,413 |
| Energy Management | 19 | 12,323,305 |
| Fans | 1 | 2,861,994 |
| HVAC | 8 | 4,049,007 |
| Motors | 3 | 207,161 |
| Other | 9 | 6,196,494 |
| Pump | 5 | 1,706,036 |
| Refrigeration | 26 | 8,070,096 |
| VFD | 23 | 12,478,908 |
| **Total*** | **106** | **56,157,060** |

*Does not include GMI project counts and savings.

Custom Projects engineers and the key account energy advisors visited large C&I customers to conduct initial facility walk-throughs, commercial/industrial efficiency program informational sessions, and training on specific technical energy-saving opportunities. Virtual/remote capabilities were implemented when health or safety restrictions were necessary. Idaho Power also provided sponsorship for the 2022 ASHRAE Technical Conference that focused on Integrating with Nature and had numerous energy efficiency related presentations. Custom Projects engineers gave presentations on Idaho Power programs and offerings at the Cohort for Schools Final Workshop, the Treasure Valley Water Summit, and two presentations at Wastewater Cohort Workshops (virtual).

The Streamlined Custom Efficiency (SCE) offering works to keep vendor engagement high, targeting projects that are typically too small to participate under the Custom Projects option. Currently, the SCE offering provides custom incentives for refrigeration controllers for walk-in coolers, process related VFDs, 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 2022, the SCE offering processed 18 projects totaling 6,365 MWh of savings and $667,555 in incentives.

#### *Cohorts*

Idaho Power has SEM cohorts to engage with customers in group settings, allowing interaction and economies of scale in working with multiple customers on SEM.

The Water Supply Optimization Cohort (WSOC), Wastewater Energy Efficiency Cohort (WWEEC), and the Continuous Energy Improvement (CEI) Cohort for Schools program offerings are driving a significant number of new projects in addition to increasing vendor engagement from the SCE offering while providing high levels of customer satisfaction. Reported cohort savings correlate to energy management incentives; any capital projects promoted or identified in SEM are reported and incentivized through the Custom Projects, New Construction or Retrofits options of the C&I Program, not as a cohort savings number.

Cohorts are structured to offer three phases of support.

1. The active phase, typically the first two years of engagement with strong consultant support, includes energy team development, energy policy development, energy model creation, training and report-out workshops, energy champion and team calls, and general energy awareness.
2. The maintaining phase includes medium consultant support and is typically years three through five or six. This phase includes consultant maintenance of facility energy models, monthly energy champion calls, report-out workshops, and ongoing general development.
3. The sustaining phase is typically beyond year five or six where the participants manage activities on their own including maintenance of energy models and ongoing focus on energy-saving activities with little consultant support. Participants in this phase have the option to participate in report-out workshops but cohort-related energy savings are no longer claimed, and consultant support is minimal.

**Water Supply Optimization Cohort (WSOC).** The WSOC began in January 2016. The goal of the cohort is to equip water professionals with the skills necessary to independently identify and implement energy efficiency opportunities that produce long-term energy and cost savings. The Eastern Idaho Water Cohort (EIWC) began in January 2018 with the goal to offer the WSOC to the eastern part of Idaho Power's service area. These two cohorts are collectively represented under the WSOC offering, despite EIWC being two years junior to WSOC in terms of program life.

Sixth-year incentives (WSOC) and savings totaled $3,723 and 238,929 kWh per year. For the participants in EIWC, fourth-year incentives and savings totaled $1,921 and 488,318 kWh per year. Combined, incentives and savings totaled $5,644 and 727,247 kWh per year.

Idaho Power continued the cohort for 10 of the original 15 WSOC participants and both EIWC participants will be continuing in the offering. Two participants are in the maintaining phase and 10 are in the sustaining phase. Idaho Power's contractor periodically contacted participants to check on project progress and opportunities and to address energy model data updates.

**Wastewater Energy Efficiency Cohort (WWEEC).** In January 2014, Custom Projects launched WWEEC, a two-year cohort training approach and incentives for low-cost or no-cost energy improvements for 11 municipal wastewater facilities in Idaho Power's service area. In 2016, Idaho Power increased the duration of WWEEC to further engage customers. Five of the 11 original participants are now in the maintaining phase and six participants are in the sustaining phase. In 2021, one facility re-engaged with the cohort after major renovations; the facility was re-baselined and is currently in the active phase.

In 2022 (the sixth year), the consultant contacted the participants to check on progress, discuss opportunities, and 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 fifth program year of the Cohort for Schools ran from June 2021 through May 2022 to coincide with the standard school calendar; reported energy savings are based on the program year.

Seven school districts participated in the program in 2022. Of those seven, five districts are modeling all schools in their district. Two districts added two new facilities each in this program year for a total of 46 facilities that were engaged with the offering during the 2022 program year. The cohort is implemented by a third-party consultant that provided final savings reports for each school district, which totaled 7,380,223 kWh and incentive checks were provided totaling $129,398 for 2022.

Activities in 2022 included managing a register of energy efficiency opportunities for each facility detailing low- 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. 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 final program year workshop was held on September 15, 2022, where results were reported for the program year. Districts shared successes, lessons learned, and other details pertinent to their energy-saving journeys.

The 2022 to 2023 program year activities will continue until May 31, 2023. Idaho Power will review final M&V reports to establish energy savings and eligible costs for the program year activities and will distribute the corresponding incentives to participating school districts.

#### *Green Motors Initiative*

Idaho Power participates in the Green Motors Practices Group's (GMPG) Green Motors Initiative (GMI). Under the GMI, service center personnel are trained and certified to repair and rewind motors 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 $2.00 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA)-rated motor up to 5,000 hp that receives 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 2022, a total of nine C&I customers' motors were rewound, and the savings for the GMI was 19,851 kWh.

### Program Activities—New Construction

In 2022, a total of 88 projects were completed, resulting in 27,615,777 kWh of energy savings in Idaho and Oregon. New Construction had an 8% reduction in number of projects and a 57% increase in total savings compared to 2021. The C&I construction industry was extremely active in Idaho Power's service area in 2022, although the industry is experiencing labor shortages and supply chain issues that have delayed, slowed, and complicated some projects.

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 strives to keep the New Construction option consistent by making changes approximately every other year. The program offerings were last updated on June 15, 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. The PAI is equal to 20% of the participant's total incentive with a maximum allowed of $5,000 per application.

The PAI increases the engagement with architects and engineers and is 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.

In 2022, a total of 43 projects, or 49% of the projects paid, received the PAI compared to 40 projects, or 42% of the total projects paid, in 2021. The PAI will continue to be offered due to positive feedback from customers, architects, and engineers.

In 2022, Idaho Power collaborated with IDL and revised the on-site verification process. The new process ensures that the final project documentation aligns with field installation before project payment. On-site project verification occurred on eight of the 88 projects, 9% of the total projects completed.

The New Construction engineers and Idaho Power energy advisors continued outreach to customers, professionals, and professional organizations throughout 2022. Meetings were held with specific customers or professionals to build relationships with the local design community and to discuss Idaho Power's New Construction option as well as the overall C&I Energy Efficiency Program. An Idaho Power representative attended eight Lunch and Learn sessions provided by the IDL to provide energy efficiency program information to attendees. Additionally, Idaho Power EOEAs and New Construction engineers presented program information to one professional organization, two Pocatello design firms, two Twin Fall design firms and three Boise area design firms with their clients. Energy efficiency program information was also hand delivered to five Pocatello design firms. Idaho Power energy advisors also provided energy efficiency program information during customer visits and calls.

See *Supplement 2: Evaluation* for the complete IDL report.

### Program Activities—Retrofits

The Retrofits option achieved 22,890,678 kWh of energy savings in 2022, representing 525 projects. Lighting retrofits comprised most of the energy savings and project count.

Idaho Power offered two in-person technical lighting training classes for trade allies and large customers on the topic of networked/luminaire level lighting controls. The company received feedback that while there was interest in attending the training, many trade allies were too busy to do so. Retrofits staff also provided virtual online training to trade allies, as requested.

The company posted a lighting tool tutorial to the Retrofits website for trade allies and customers wanting to take part in a self-directed learning opportunity on how to use the lighting tool.

Idaho Power continued its contracts with various consultants to provide ongoing program support for lighting and non-lighting reviews and inspections, as well as trade ally outreach.

### Marketing Activities

Idaho Power continued to primarily market the C&I Energy Efficiency Program as a single offering to businesses.

See the C&I Sector Overview for the company's additional efforts to market the C&I Energy Efficiency Program. Below are the option-specific marketing efforts for 2022.

#### *Custom Projects*

In addition to program-level marketing activities, Idaho Power created multiple brochures including a Custom Projects program overview, Industrial Wastewater Cohort brochure, and Water Leaks brochure. Idaho Power continued to present large-format checks to interested

Custom Projects participants and publicized these events to local media, when applicable. Several of these were facilitated by key account energy advisors in 2022.

In 2022, Idaho Power continued to promote GMI as part of the C&I Energy Efficiency Program marketing efforts.

#### *New Construction*

The company 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 2022.

#### *Retrofits*

The company placed two pop-up ads on My Account: one in February that resulted in 4,693 views and 52 clicks and the second in May that resulted in 7,096 views and 42 clicks from business customers.

The company placed an ad twice in the Pocatello Chamber of Commerce newsletter in March and ran a marquee on their website. In April, the company mailed 1,420 letters promoting Retrofits to Boise Metro Chamber of Commerce members. Periodically, the company sent out emails promoting the lighting incentives. The company's customer solutions advisors then followed up by making personal phone calls to customers who received the email.

### 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. 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 are available under the Custom Projects option.

The UCT and TRC ratios for the program are 2.88 and 1.12, respectively. Non-energy impacts were applied in 2022 based on an estimated per-kWh value by C&I 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. When precise measurements are unavailable, savings are calculated based on industry-standard assumptions. 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 and the International Energy Conservation Code (IECC) to calculate the savings based on an assumed baseline (i.e., 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.

The UCT and TRC ratios for the program are 4.25 and 3.64, respectively. Non-energy impacts were applied in 2022 based on an estimated per-kWh value by C&I end-uses. These values were provided by a third party as part of the 2019 impact evaluation of the New Construction and Retrofits options. The increase in the program's overall cost-effectiveness is largely due to the increase in savings between 2021 and 2022. Finally, if the amount incurred for the 2022 evaluation was removed from the program's cost-effectiveness, the UCT would be 4.34, while the TRC would be 3.70.

Complete, updated measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

#### *Retrofits*

For 2022, Idaho Power used most of the same savings and assumptions as were used after the program changes in 2021 for the Retrofits option. For all lighting measures, Idaho Power uses a Lighting Tool developed by a third party. An initial analysis is conducted to see if the lighting measures shown in the tool are 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 *Technical Reference Manual* (TRM) or the RTF are used to calculate the cost-effectiveness.

The UCT and TRC ratios for the program are 2.01 and 1.11, respectively. Non-energy impacts were applied in 2022 based on an estimated per-kWh value by C&I end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options. Finally, if the amount incurred for the 2022 evaluation was removed from the program's cost-effectiveness, the UCT would be 2.03, while the TRC would be 1.11.

Complete updated measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction

In 2022, a survey was sent to Retrofits customers who had a lighting project installed by a contractor to evaluate the customers' satisfaction level for the contractors listed on the 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 243 program participants in 2022. Idaho Power received survey results from 76 respondents. Some highlights include the following:

- More than 63% of respondents learned of the program from a contractor, and more than 14% learned of the program from an Idaho Power employee.
- Nearly 83% of respondents said they were "very satisfied" with the program, and more than 14% of respondents indicated they were "somewhat satisfied."
- More than 89% of respondents said they were "very satisfied" with the contractor they hired to install their equipment, and more than 9% of respondents indicated they were "somewhat satisfied."
- More than 89% of respondents said they were "very satisfied" with the equipment installed, and nearly 8% of respondents said they were "somewhat satisfied."

A copy of the survey results is included in *Supplement 2: Evaluation*.

### Evaluations

The Custom Projects option process and impact evaluation was done in 2021, but due to the timing of receiving the report all recommendations were not addressed in the *Demand-Side Management 2021 Annual Report*. The evaluation found a successfully run program that has mitigated many of the risks associated with custom energy efficiency programs. The evaluation team identified only minor adjustments to claimed savings and calculated a realization rate of 99.8%. The process evaluation recommended three items that were addressed in 2022:

*Update the commercial and industrial program logic model to include recent program updates.* This was done to include provision for new energy management and other program details in 2022.

*Add a new construction or equipment replacement check box for the program application*. This was considered but not chosen for implementation given the complexity of some Custom projects and potential confusion of which box to check. A Custom Projects check box and Custom Projects information tab were added to the prescriptive New Construction preliminary application and Custom Projects engineers were made aware of the project for additional follow-up.

*Continue to focus on efficient and effective communication between all parties*. As COVID-19 restrictions eased, more in-person trainings and customer visits were conducted. Hybrid meetings (in-person with virtual option) were scheduled, allowing increased access and attendance for customers, staff, and stakeholders.

A complete copy of the evaluation is included in *Supplement 2: Evaluation*.

#### *New Construction*

The New Construction option process and impact evaluation was conducted in 2021 and the report was finalized in 2022. The evaluation found a successfully run program that actively engages with the marketplace on new construction projects to impact the design and construction of new C&I facilities. The program stays current with code requirements and works with individual buildings to ensure they exceed code for the appropriate design and construction period. The evaluation team found only slight adjustments to ex-ante savings claimed in the 2021 program and limited opportunities for process improvements. The evaluation team calculated a realization rate of 102.5%. Following are the recommendations from the evaluation and Idaho Power's plan for each one.

*Document project worksheets at stages throughout the process*. Idaho Power will incorporate this recommendation going forward.

*Increase program review and feedback of the submitted code-checking software, COMcheck*. Idaho Power will review and revise the lighting review checklist to incorporate this recommendation in 2023.

*Document the HVAC control systems that meet code and exceed code*. Idaho Power will review and revise the HVAC control review checklist to incorporate this recommendation in 2023.

*Continue to expand in-person outreach and program overview training where possible.* Idaho Power will continue to provide in-person outreach and program overview training in 2023. New Construction will attend Retrofit workshops in 2023 to increase the cross-training between program options.

*Consider developing a consolidated contractor list across CIEE program with substantial overlap*. Idaho Power CIEE program staff will develop a consolidated contractor list in 2023.

*Consider a leave-behind brochure for contractors with all CIEE program offerings.* Idaho Power has a CIEE leave-behind brochure for contractors, architects, and engineers. The company will review potential benefits to updating the brochure to provide enhanced clarity to the various program options available for customers; in addition, the company will review opportunities to increase brochure distribution in 2023.

The complete copy of the evaluation is included in *Supplement 2: Evaluation*.

#### *Retrofits*

The Retrofits option process and impact evaluation was conducted in 2021 and the report was finalized in 2022. The evaluation for the Retrofits option found a successfully run program that balances the use of prescriptive assumptions and values with the data collection from the project site. The program stays current with baseline requirements and the program savings calculations are accurate and well-documented. The overall realization rate for the Retrofits option is 96.4%. Following are the recommendations from the evaluation and Idaho Power's responses.

*Develop the exterior lighting controls savings factors.* Idaho Power will incorporate this recommendation in its lighting tool update in 2023.

*Document lighting control savings for transparency to the applicant.* Idaho Power will incorporate this recommendation in its lighting tool update in 2023.

*Consider incorporating interactive effects into the Retrofits lighting tool.* Idaho Power reviewed this recommendation and determined it will not incorporate interactive effects into the lighting tool. The Retrofits team is presently looking for ways to streamline the lighting tool to encourage increased participation in the program. Adding additional information for project submitters to address would be a barrier to participation. In addition, the company would prefer not to incur costs for programming the lighting tool to capture interactive effects.

*Consider adjusting the anti-sweat heater measure to differentiate between medium- and low-temperature refrigeration.* Idaho Power will incorporate this recommendation as part of the Retrofits program update in 2023.

*Continue to increase in-person program overview training where possible.* Idaho Power will continue to increase in-person trainings, to include holding in-person Retrofit program workshops for trade allies in 2023.

*Consider developing a consolidated contractor list across CIEE programs with substantial overlap.* Idaho Power CIEE program staff will develop a consolidated contractor list in 2023.

*Consider a leave-behind brochure for contractors with all CIEE programs.* Idaho Power has a C&I Energy Efficiency Program leave-behind brochure for trade allies. The company will review potential opportunities to update the existing brochure to provide enhanced clarity to the various program options available for customers; in addition, the company will review opportunities to increase brochure distribution in 2023.

The complete copy of the evaluation is included in *Supplement 2: Evaluation*.

### 2023 Plans

In 2023, the three options will continue to be marketed as part of Idaho Power's C&I Energy Efficiency Program. Below are specific program option strategies.

#### *Custom Projects*

In 2023, the company plans to expand deployment of the commercial energy-savings tool, Find n' Fix, which, in conjunction with engineering services, helps identify and quantify energy savings opportunities for commercial customers. Also, the compressed air leak detection and repair offering that is available to larger customers, like the water-leak measure launched in 2020, will be marketed and expanded in 2023.

Activities and coaching will continue for the school, water, and wastewater cohort participants.

The Industrial Wastewater Energy Cohort officially began in September of 2022. This cohort focuses on a more technical approach to energy savings than the other water and wastewater cohorts. Recruitment and energy scans to identify electrical energy saving opportunities have been completed and active savings have begun. This cohort offers technical trainings that are extended to non-cohort participants to continue the engagement of customers in the Idaho Power programs.

Idaho Power is currently in the process of contracting for a new cohort called the Campus Cohort for Energy Efficiency. This cohort will be structured similarly to the existing cohorts but will focus on customers who have facilities with multiple buildings on a site, such as but not limited to universities, government installations, hospitals, and prisons.

Idaho Power will continue to provide the following:

- In-person or virtual site visits and energy scoping assessments by Custom Projects engineers to identify projects and energy savings opportunities.
- Funding for detailed energy assessments for larger, complex projects. Virtual assessments can also be offered in many cases.
- M&V of larger, complex projects. Virtual M&V can also be used as conditions allow.
- Technical training for customers, presented virtually or in person as conditions allow.

#### *New Construction*

In 2023, Idaho Power will identify and incorporate best practices and recommendations identified in the impact and process evaluation completed in 2022.

As in past years, Idaho Power will continue to build relationships in 2023 by sponsoring technical training through the IDL to address the energy efficiency education needs of design professionals throughout Idaho Power's service area.

#### *Retrofits*

Idaho Power will address the third-party impact and process evaluation recommendations as outlined above.

## Commercial Energy-Saving Kits

| | 2022 | 2021 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (kits) | 334 | 906 |
| Energy Savings (kWh) | 48,758 | 296,751 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $21,604 | $71,501 |
| Oregon Energy Efficiency Rider | $1,140 | $3,117 |
| Idaho Power Funds | $25 | $0 |
| Total Program Costs—All Sources | $22,770 | $74,617 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.059 | $0.029 |
| Total Resource Levelized Cost ($/kWh) | $0.059 | $0.029 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.78 | 1.64 |
| Total Resource Benefit/Cost Ratio | 0.87 | 2.00 |

### Description

The Commercial Energy-Saving Kit (Commercial ESK) program is offered to commercial business customers in Idaho and Oregon. One kit was offered to business customers who had not previously received a commercial kit. The kit included: two 9-watt LED A lamps, two 8-watt LED BR30 lamps, a bathroom aerator, an exit sign retrofit, and a kitchen aerator. Idaho Power used a third-party vendor for kit assembly and mailing. The vendor sent the kit directly to the customer on the company’s behalf.


**Figure 22. Commercial Energy-Saving Kit**

### Program Activities

Idaho Power contracted with a new commercial kit vendor mid-year in 2022. The company streamlined the kit offer to one kit type, which included seven measures.

**Table 18. Number of kits distributed per state and associated energy savings**

| State | Total Distributed | kWh Savings |
|---|---|---|
| Idaho* | 317 | 46,237 |
| Oregon | 17 | 2,520 |

* Includes 10 restaurant, 1 retail, and 12 office kits distributed from remaining inventory.

### Marketing Activities

In 2022, Idaho Power promoted the commercial kits using LinkedIn posts in November. Additionally, the kits were promoted in September and December in the quarterly newsletter to business customers, *Energy@Work*.

The company displayed a pop-up ad to small business customers who logged into My Account in October, November, and December, resulting in 298 users clicking on the ad. Customers signing into My Account clicked on the pop-up ad and requested a kit through the vendor's online order form.

In November, the company sent an email to 8,651 business customers. This tactic resulted in a 46.55% open rate and 118 kits were ordered that day. Idaho Power's customer solutions advisors (CSA) also promoted the commercial kit during their calls with business customers and offered to sign up customers who requested the kit during the call.

### Cost-Effectiveness

Because no deemed savings values exist for the Commercial ESK program, Idaho Power made several assumptions. When the offering launched in mid-2018, the installation rates of the items in the kit were unknown. Idaho Power estimated the installation rates based on professional judgement. Idaho Power updated this assumption in 2021 based on the follow-up survey sent to customers in 2020. In 2022, evaluators surveyed 2021 participants and updated the installation rates for each item.

For the LEDs and aerators, savings vary by kit type based on the average annual hours of use (HOU) and annual gallons of water used by business type. In 2022, energy advisors distributed 10 restaurant kits, 1 retail kit, and 12 office kits that were remaining in inventory. Based on the updated savings assumptions from the evaluation, restaurant, retail, and office kits provide approximately 192, 208, and 56 kWh of annual savings, respectively.

At the November 2021 EEAG meeting, Idaho Power shared the cost-effectiveness challenges for the kit program and proposed four possible options. With direction from EEAG, it was decided to simplify the offering to one kit, continue sending the kit per customer request, and track the business type ordering the kit. Of the 311 simplified kits distributed in 2022, 14 were distributed to restaurants, 38 were distributed to retail businesses, and 259 were distributed to offices. Based on the savings developed by the evaluators using the installation rates from the evaluation, the savings ranged from 83 kWh (non-electric office) to 500 kWh (electric restaurant).

As further discussed with EEAG in 2022, the offering continues to face cost-effectiveness challenges. When the Energy Independence and Security Act is fully implemented in July 2023, the evaluators recommended removal of LED bulbs from the kit offering going forward. Due to the declining savings opportunities and rising costs, the kits will not be cost-effective going forward.

For more information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction

In 2022, the third-party evaluator surveyed customers as part of the impact and process evaluation of the Commercial ESKs. The purpose of the surveys was to understand the installation rates of the items included in the kits as well as participants' overall satisfaction with the offering.

The majority of respondents were "satisfied" or "very satisfied" with the program (88.4%) and about half of respondents were interested in learning more about other energy efficiency opportunities through Idaho Power (51.6%). While the majority of respondents who remembered receiving a kit indicated they installed at least one measure from the kit (95.6%), Idaho Power plans to continue to survey participants, as certain items such as the LED retrofit kits for exit signs and faucet aerators had low installation rates, which impacted the savings reported for the items. Idaho Power plans to continue to survey customers to update the assumptions around installation rates.

Survey results are included in the impact and process evaluation report available in *Supplement 2: Evaluation.*

### Evaluations

In 2022, Idaho Power contracted a third party to conduct process and impact evaluations for the Commercial ESK program. Following are the recommendations of the evaluations and Idaho Power's response to each.

*To more accurately estimate verified savings, the evaluators recommend Idaho Power continue to update their in-service rate (ISR) assumptions when calculating claimed savings for future program years.* Idaho Power will continue to update the ISR assumptions.

*The evaluators recommend Idaho Power continue to update their electric water heat saturation assumptions when calculating claimed savings for future program years.* Idaho Power will monitor participating customer feedback about electrical water heat use and update program assumptions, as needed.

*The evaluators recommend Idaho Power include space heating and space cooling interactive effects when calculating claimed savings for lighting measures in the future.* Idaho Power has reviewed this recommendation and will not implement the recommendation because the company would have to put in place a way of getting information from the customer on heating and cooling system types; as the company is not certain how long it will continue the program, it prefers not to adjust any processes at this time.

*The evaluators recommend Idaho Power alter assumed hours of use for retail applications to 4,533 hours per year.* Idaho Power will update the retail hours of use per the recommendation.

*The evaluators recommend that Idaho Power plan to remove LED measures from the Commercial Energy-Saving Kits Program. The resulting verified savings for the measure will be claimable until July 1, 2023. After this date, third party evaluators must assume that all unqualified lighting measures have been replaced by LED measures due to burnout.* Idaho Power will discontinue offering LED measures in a commercial kit by July 1, 2023.

*The evaluators recommend that Idaho Power provide more opportunities for participating customers to learn about other offerings Idaho Power provides.* Idaho Power evaluates its marketing efforts to business customers to learn about the various available energy efficiency programs on a regular basis. The company will take this recommendation under advisement as it pursues marketing efforts in 2023.

*The evaluators recommend Idaho Power staff reconsider the inclusion of retrofit exit signs and low-flow aerators altogether for kits moving forward. Although these measures can garner energy savings, they are not popular among kit recipients and thus may not be cost-effective measures to provide consumers. Rather than provide unwanted measures, such as retrofit exit signs, pre-rinse spray valves, and low-flow aerators, Idaho Power staff should consider providing other measures such as occupancy sensors, as customers indicate a desire for such applications*. Idaho Power included low-flow aerators and retrofit exit signs in its most recent single kit offering; however, the company scaled back to one of each. Idaho Power plans to consult its commercial kit vendor to identify any additional measures that could be cost-effectively viable to install in a future commercial kit.

The complete impact and process evaluation report can be found in *Supplement 2: Evaluation.*

### 2023 Plans

In 2023, Idaho Power will continue to market the program until the contract is complete. In addition, Idaho Power will send customer satisfaction surveys to program participants.

## *Flex Peak Program*

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (buildings) | 159 | 139 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW)* | 24.5/30.0 | 30.6/36.0 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $84,582 | $101,236 |
| | Oregon Energy Efficiency Rider | $151,148 | $175,121 |
| | Idaho Power Funds | $283,888 | $225,617 |
| | Total Program Costs—All Sources | $519,618 | $501,973 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/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 |

* Maximum actual demand reduction/maximum potential demand reduction. Demand response program reductions are reported with 9.7% peak loss assumptions.

### 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 C&I customers with the objective to reduce the demand on Idaho Power's system during periods of extreme peak electricity use.

Program event parameters include the following:

- June 15 to September 15 (excluding weekends and holidays)
- Up to four hours per day between 3 and 10 p.m.
- Up to 16 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 four 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 2022, 69 participants enrolled 159 sites in the program. Existing customers were automatically re-enrolled. Participants had a committed load reduction of 29.5 MW in the first week of the program and ended the season with a committed load reduction of 27.2 MW. The estimated maximum capacity of the program came from the nominated amount in the third week of the season at 30 MW.

This weekly commitment, or nomination, was comprised of all 159 sites. The maximum realization rate during the season was 86%, and the average for the seven events was 62%. 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 24.5 MW (at generation level) during the July 28 event (Table 19).

**Table 19. Flex Peak Program demand response event details**

| Event Details | Tuesday, July 26 | Thursday, July 28 | Monday, August 8 | Wednesday, August 17 | Wednesday, August 31 | Friday, September 2 | Tuesday, September 6 |
|---|---|---|---|---|---|---|---|
| Event time | 5–9 p.m. | 5–9 p.m. | 5–9 p.m. | 5–9 p.m. | 6–10 p.m. | 5–9 p.m. | 5–9 p.m. |
| Average temperature | 97.0° F | 101.6° F | 101.0° F | 97.0° F | 96.3° F | 98.3° F | 102.0° F |
| Maximum load reduction (MW) | 18.7 | 24.5 | 21.1 | 21.1 | 19.2 | 14.4 | 15.6 |

Event performance and realization rates for the 2022 season were lower than prior years in the program. Impacts from COVID-19 with respect to supply chain and production issues appears to still be playing a role in participants' ability to reduce load.

### Marketing Activities

New program parameters per IPUC Case IPC-E-21-32 and OPUC Docket No. ADV 1355/Advice No. 21-12 (replacing the IPC-E-13-14/UM 1653 Settlement agreement) went into effect in 2022.

In 2022, the program brochures and website were updated to reflect the new program parameters. The company ran a My Account pop-up ad promoting enrollment to large commercial customers. In May, the company launched a new email and direct-mail marketing tactic to 18 national accounts in its service area. Additionally, a LinkedIn post in May promoted program enrollment, and a thank-you note to participants was posted on LinkedIn in November. 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 C&I Sector Overview.

### Cost-Effectiveness

Idaho Power determines cost-effectiveness for its demand response program using the approved method for valuing demand response under IPUC Order No. 35336 and the OPUC's approval on February 8, 2022 in Docket No. ADV 1355. Using the financial and alternate resource cost assumptions from the *2021 Integrated Resource Plan*, the defined cost-effectiveness threshold for operating Idaho Power's three demand response programs for the maximum allowable 60 hours is $82.91 per kW under the current program parameters.

The Flex Peak Program was dispatched for 28 event hours and achieved a maximum load reduction of 24.5 MW and a maximum nomination capacity of 30 MW throughout the season. The total cost of the program in 2022 was $519,618. Had the Flex Peak Program been used for the full 60 hours, the potential cost would have been approximately $700,200. Using the potential cost and the average maximum capacity results in a cost of $23.34 per kW, which shows the program was cost-effective.

A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction

In November, Idaho Power sent surveys to program participants and non-participants. The purpose of the surveys was to evaluate the motivators and barriers to participation as well as gauge customers' likelihood to participate in the program under varying program designs. Participants were asked additional questions around their overall satisfaction with the program and the ease of participation.

Idaho Power received 33 responses from the participant survey and 25 responses from the non-participant survey. Some highlights include the following:

- For participants, nearly 55% of respondents participated in the program because they wanted to earn an incentive for providing demand reduction while 27% participated because they wanted to help reduce overall electrical usage on hot summer days. For non-participants, almost 52% of the respondents did not participate in the program because they did not know about it while nearly 30% of respondents indicated it would negatively impact their business.
- Overall, 76% of participant survey respondents indicated they were "very satisfied" or "somewhat satisfied" with the Flex Peak program with 84 to 94% of respondents indicating they were "very satisfied" or "somewhat satisfied" with various components of the program including the program support from Idaho Power, post-performance data, and timeliness of receiving the incentive payment/bill credit.

- Nearly 85% of participant survey respondents indicated they are “very likely” or “somewhat likely” to participate in the program in 2023.
- Respondents were asked their likelihood to participate in the program if Idaho Power limited the number of times the program could be called each week at a reduced incentive level.
    - Under all scenarios, 42 to 48% of current participants indicated they are “very unlikely” or “somewhat unlikely” to participate in the program under the proposed hypothetical scenario options.
    - Under all scenarios, 40 to 52% of current non-participants indicated they are “very unlikely” or “somewhat unlikely” to participate in the program under the proposed hypothetical scenario options.

A copy of the survey results is included in *Supplement 2: Evaluation.*

### Evaluations

Idaho Power conducted an internal evaluation of the program’s potential load-reduction impacts. A copy of this report is in *Supplement 2: Evaluation*.

In 2021 Idaho Power engaged a third-party contractor to conduct an impact evaluation of the Flex Peak Program. The evaluation found the Flex Peak Program to have been operated effectively in 2021, and the method for calculating demand reductions to have been appropriately applied with only minor discrepancies, mostly related to rounding practices.

Recommendations from this evaluation are listed below, followed by Idaho Power’s response:

*Use consistent rounding practices and streamline analytical approach through computer scripting and develop documentation regarding rules for handling errors, missing data, and other data validation steps*. Idaho Power has developed a Statistical Analysis System (SAS) program to input all metering data and run all calculations. This was developed to make all calculations consistent, remove human error and to streamline the calculation process.

*Establish data validation and quality control protocols.* The developed SAS code is written to remove erroneous data and to flag errors that would affect baseline calculations for human review.

*Continue to work with customers to refine their nominated load reductions.* The program specialist and energy advisors continue to work with participants to identify nominations that need to be refined to reflect realistic load reductions more accurately.

### 2023 Plans

For the 2023 program season, Idaho Power has requested program changes from the IPUC and the OPUC. These changes will add an automatic dispatch option feature to the program that Idaho Power believes may make it easier for some customers to participate.

The company will continue to communicate the program value with enrolled customers and the importance of active participation when events are called. Idaho Power will meet with existing participants during the off-season to discuss past season performance and upcoming season details.

For the upcoming season, Idaho Power will continue its focus on retaining currently enrolled participants and will be using email marketing, paid search, digital display, and other tactics to boost program enrollment, with a focus on enrolling national chain stores within Idaho Power's service area. Energy assessments conducted by Idaho Power engineers or contract engineers will be offered to large customers that haven't participated in the past to help determine potential for load shed and identify specific load shed tactics and sequences that could be initiated for events. The program will also continue to be marketed along with the C&I Energy Efficiency Program.

## Oregon Commercial Audits

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (audits) | 12 | 3 |
| | 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 | $7,493 | $4,401 |
| | Idaho Power Funds | $0 | $0 |
| | Total Program Costs—All Sources | $7,493 | $4,401 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/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 C&I 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 no-cost 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 an opportunity 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

During 2022, there were 12 audits completed at separate facilities for five customers. The program contractor conducted the audits, and an Idaho Power energy advisor was available to assist customers.

### Marketing Activities

Idaho Power sent its annual direct-mailing to 1,557 Oregon commercial customers in December 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 Audits 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.

### 2023 Plans

Idaho Power does not expect to make any operational changes in 2023. 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

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (audits) | 680 | 452 |
| | Energy Savings (kWh) | 3,228,365 | 2,421,842 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $1,317,820 | $1,052,943 |
| | Oregon Energy Efficiency Rider | $27,558 | -$20,887 |
| | Idaho Power Funds | $51 | $0 |
| | Total Program Costs—All Sources | $1,345,429 | $1,032,056 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.049 | $0.062 |
| | Total Resource Levelized Cost ($/kWh) | $0.049 | $0.062 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 0.95 | 0.99 |
| | Total Resource Benefit/Cost Ratio | 1.50 | 1.54 |

### Description

Idaho Power launched the SBDI program in November 2019 targeting typically hard-to-reach, small business customers in Idaho who use less than 25,000 kWh annually. Idaho Power pays 100% of the cost to assess eligibility and install lighting measures for these customers, using a third-party contractor to operate the program. SBDI is offered to eligible customers in a strategic geo-targeted approach.

### Program Activities

In 2022, the company continued offering the SBDI program to customers in southern Idaho, expanding to the company's Treasure Valley area early in the year. Idaho Power sent direct-mail letters to customers informing them of their eligibility to participate, and the contractor followed up with calls offering another opportunity to hear about the program and 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. The SBDI contractor scheduled 823 lighting assessments, completed 680 project installations, and completed 70 post-installation inspections.

### Marketing Activities

Idaho Power sent 4,054 direct-mail letters to business customers in the Capital Region, 3,179 letters to business customers in the Canyon-West Region, and 253 letters to business customers in the Southern Region in 2022. The program contractor followed up with 2,100 phone calls after customers received the letters.

### Cost-Effectiveness

In 2022, 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 0.95 and 1.50 respectively. Non-energy impacts were applied in 2022 based on an estimated per kWh value by C&I end-uses. These values were provided by a third-party as part of the 2019 impact evaluation of the New Construction and Retrofits options. In 2022, Idaho Power discussed the cost-effectiveness challenges facing the program in the future with EEAG. These challenges include the reduced savings potential from screw-in bulbs and increased costs associated with materials and labor. As the cost of this free service rises, it will be increasingly difficult for the program to be cost-effective from the UCT perspective. As a result, the offering will close in March 2023 once the program has been fully offered across the service area.

Details for the program cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction

Idaho Power's third-party implementer sent 680 customer satisfaction surveys to program participants in 2022, of which 196 surveys were completed. Key highlights include the following:

- More than 95% of respondents said they were "very satisfied" with the program, and just over 4% of respondents indicated they were "somewhat satisfied."
- Nearly 96% of respondents found it "very easy" to participate in the program and almost 4% reporting it was "somewhat easy" to participate in the program.
- All respondents reported they would be likely to recommend the program to other small businesses, with over 92% of respondents saying they were "very likely" and nearly 8% reporting they were "somewhat likely."
- All respondents were satisfied with the equipment installed at their business, with nearly 95% of respondents reporting they were "very satisfied" and just over 5% of respondents saying they were "somewhat satisfied."
- When asked how their opinion of Idaho Power has changed since participating in the program, over 58% of respondents reporting having a more favorable opinion of Idaho Power, and nearly 42% of respondents reported no change in opinion.

As part of the process evaluation conducted on the program in 2021, the evaluators recommended additional customer satisfaction follow-up with nonresponding customers. In 2022, Idaho Power worked with the third-party implementer to identify non-respondents to the implementer's customer satisfaction survey. Idaho Power sent 296 customer satisfaction surveys to program participants in 2022, of which 47 surveys were completed. Key highlights include the following:

- More than 89% of respondents said they were "very satisfied" with the program, and more than 8% of respondents indicated they were "somewhat satisfied."
- More than 94% of respondents reported they were "very satisfied" with the equipment installed, and more than 6% of respondents indicated they were "somewhat satisfied."
- More than 89% of respondents said they were "very satisfied" with the customer service provided by the company installing the equipment, and more than 6% of respondents indicated they were "somewhat satisfied."

A copy of the survey results is included in *Supplement 2: Evaluation*.

### 2023 Plans

Idaho Power will continue to operate this program as described above until the program has been fully offered across its service area, which is March 2023; at that time Idaho Power will close the program.

## 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 2022, the active irrigation service locations totaled 21,324 system-wide, which is an increase of 1.2% compared to July 2021. 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 1,949,766 MWh of energy usage in 2022, versus 2,125,733 MWh in 2021. The approximately 8% decrease is primarily because of substantial rain that occurred in June. This sector represented nearly 12.3% of Idaho Power's total electricity sales, and approximately 29% of July sales. Though annual electricity use may vary substantially for weather-related reasons, and there are now more irrigation customers, the energy-use trend for this sector has not changed significantly in many years because of the following:

- The added energy usage from new customers is relatively small compared to the energy use of the average existing customer
- Ongoing improvements through energy efficiency efforts and system replacement offset much of the added energy use

The Irrigation Efficiency Rewards program, including the GMI, experienced decreased annual savings: from 9,699,849 kWh in 2021 to 6,954,805 kWh in 2022. This was due primarily to a decrease in the savings and measures from small maintenance upgrades in the Menu Incentive Option of the program.

Idaho Power re-enrolled the majority of the 2021 Irrigation Peak Rewards participants in 2022, with 2,142 service points and a maximum load reduction potential of 255.6 MW. Table 20 summarizes the overall expenses and program performance for both programs and shows the actual load reduction was 155.1 MW.

**Table 20. Irrigation sector program summary, 2022**

| | | | Total Cost | | Savings | |
|---|---|---|---|---|---|---|
| Program | Participants | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW)* |
| **Demand Response** | | | | | | |
| Irrigation Peak Rewards | 2,142 | service points | $ 8,503,140 | $ 8,503,140 | | 155.1/255.6 |
| **Total** | | | **$ 8,503,140** | **$ 8,503,140** | | **155.1/255.6** |
| **Energy Efficiency** | | | | | | |
| Irrigation Efficiency Rewards | 519 | projects | 2,080,027 | 14,083,686 | 6,937,855 | |
| Green Motors Initiative—Irrigation | 6 | motor rewinds | 0 | 5,634 | 16,950 | |
| **Total** | | | **$ 2,080,027** | **$ 14,089,320** | **6,954,805** | |

**Notes:**

See Appendix 3 for notes on methodology and column definitions.

Totals may not add up due to rounding.

* Maximum actual demand reduction/maximum demand capacity. Demand response program reductions are reported with 9.7% peak loss assumption.

## *Irrigation DSM 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.

**Irrigation Peak Rewards.** A demand response program designed to reduce load from irrigation pumps during periods of high energy demand or for other system needs. Participating service points are automatically controlled by Idaho Power switches or manually interrupted by the customer for very large pumping installations or when switch communication is not available.

**Green Motor Initiative.** Under the 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." 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.

## *Marketing*

In 2022, 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, momentary outage improvements, planning for safety, My Account information, changes to the Irrigation Efficiency Rewards program, and updates to the Irrigation Peak Rewards program.

The application for new or upgraded service was put into a tear-pad version so during one-on-one visits agricultural representatives (ag reps) could easily tear off an application and provide to irrigator.

The company also placed numerous print ads in agricultural publications to reach the target market in smaller farming communities. Publications included the *Capital Press*, *Power County Press/Aberdeen Times*, *Potato Grower* magazine, *Owyhee Avalanche*, and *The Ag Expo East and West* programs. Idaho Power used radio advertising to show support for the Future Farmers of America and Ag Week conferences.

January through March, the company ran 1,796 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, adult hits, and country.

### Customer Satisfaction

Idaho Power conducts the *Burke Customer Relationship Survey* each year. In 2022, on a scale of zero to 10, irrigation survey respondents rated Idaho Power 8.08 regarding offering programs to help customers save energy, and 7.95 related to providing customers with information on how to save energy and money. Twenty-three percent of irrigation 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, 89% are “very” or “somewhat” satisfied with the program.

### Training and Education

Idaho Power continued to market its irrigation programs by offering virtual and in-person workshops and offering new presentations to irrigation customers. In 2022, Idaho Power provided three virtual irrigation workshops for the Irrigation Efficiency Rewards and Irrigation Peak Rewards programs; this number was greatly reduced compared to a typical year due to COVID-19. Approximately 18 customers attended virtual workshops. In December 2022, Idaho Power provided one in-person workshop in Oregon with 20 customers in attendance. In October program staff attended the first annual Idaho Farm and Ranch Conference in Boise and hosted a booth.

### Field Staff Activities

Idaho Power agricultural representatives (ag reps) were available to be on-site with customers in 2022, offering Idaho Power energy efficiency and demand response program information, education, training, and irrigation system assessments and audits across the service area.

Also, in 2022, ag reps continued their engagement with agricultural irrigation equipment dealers with the goal of sharing expertise about energy-efficient system designs and increasing awareness about the program. Ag reps and the irrigation segment coordinator, a licensed agricultural engineer, participated in training sponsored by the nationally based Irrigation Association to maintain or obtain their Certified Irrigation Designer and Certified Agricultural Irrigation Specialist accreditations.

## Irrigation Efficiency Rewards

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings*** | | | |
| | Participants (projects) | 525 | 1,031 |
| | Energy Savings (kWh) | 6,954,805 | 9,699,849 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $1,950,122 | $2,350,620 |
| | Oregon Energy Efficiency Rider | $74,622 | $221,523 |
| | Idaho Power Funds | $55,284 | $35,057 |
| | Total Program Costs—All Sources | $2,080,027 | $2,607,200 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.027 | $0.023 |
| | Total Resource Levelized Cost ($/kWh) | $0.179 | $0.166 |
| **Benefit/Cost Ratios**** | | | |
| | Utility Benefit/Cost Ratio | 2.69 | 3.32 |
| | Total Resource Benefit/Cost Ratio | 2.54 | 4.49 |

* 2021 total includes 19,352 kWh of energy savings from 12 Green Motors projects. 2022 total includes 16,950 kWh of energy savings from 6 Green Motors projects.

** 2021 cost-effectiveness ratios include evaluation expenses. If evaluation expenses were removed from the program's cost-effectiveness, the 2021 UCT and TRC would be 3.34 and 4.49, 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 Option and Menu Incentive Option. 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 the standard before approving the incentive. If an existing irrigation system is changed to a new water source, it is considered a new irrigation system under this program. The incentive for a new system is $0.25 per estimated kWh saved in one year, not to exceed 10% of the project cost.

For existing system upgrades, the incentive is $0.25 per estimated kWh saved in one year or $450 per estimated kW demand reduction, whichever is greater. The incentive is limited to 75% of the total project cost.

The qualifying energy efficiency measures include 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 and analyzes each project, considering prior usage history, irrigation system maps, system design details, invoices, and, in many 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 7 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

Incentives are based on a predetermined kWh savings per component from the RTF. Based on the evaluation that the RTF completed in 2021, the kWh annual savings changed for many components with some components being removed because the savings were no longer supported. On January 1, 2022, Idaho Power changed the list of eligible components to exclude new wheel-line hubs, goosenecks, pipe repair, and center pivot base boot gaskets. Any invoice dated prior to January 1, 2022, was eligible for the previous measures and incentive amounts for up to one year from the date of the invoice.

#### *Green Motors Initiative*

Idaho Power also participates in the GMPG GMI. Under the initiative, Idaho Power pays service centers $2.00 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 2022, a total of 519 projects were completed: 439 Menu Incentive Option projects that provided an estimated 2,633 MWh of energy savings, and 80 Custom Incentive Option projects that provided 4,305 MWh of energy savings (45 new systems and 35 existing systems).

Also, a total of six irrigation customers' motors were rewound under the GMI and accounted for 16,950 kWh in savings.

### Marketing Activities

In addition to activities mentioned in the Irrigation Sector Overview, the Idaho Power ag rep and program specialist worked one-on-one with irrigation dealers and vendors who are key to the successful promotion of the program. In March 2022, the ag reps held three virtual workshops. The content was the same but offered a morning, noon, and afternoon option on three different days so customers could easily join. The virtual seminar focused on the Irrigation Efficiency Rewards program, Idaho Power's website, and self-help tools. The ag rep also visited each irrigation vendor in their area to distribute new menu efficiency applications and explain the program changes.

### Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements for the Custom Incentive Option and the Menu Incentive Option.

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 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 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.

The RTF irrigation hardware maintenance workbook version 5.3 is the source of all savings assumptions for the Menu Incentive Option. In spring 2021, the RTF updated the savings assumptions for the irrigation hardware measures based on survey results from Idaho Power, BPA, and PacifiCorp. While measure savings did not change significantly, the survey results did support an increase in the measure life from 4–5 years to 6–7 years. However, four measures (wheel-line hubs, goosenecks with drop tube, cut and pipe press or weld repair, and new center pivot base boot gaskets) showed little to no savings, thus those measures were removed from the updated irrigation workbook. With no supported savings, Idaho Power removed the measures from the Menu Incentive Option in 2022.

The changes to the measure offerings were effective on December 31, 2021. Any invoice dated December 31, 2021, or before and submitted within one year was processed under the prior program measure incentive list. For invoices with dates of January 1, 2022, and later, the applications were processed under the updated measure list and incentive levels.

The UCT and TRC for the program are 2.69 and 2.54, respectively.

Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*. Assumptions for measures processed before the program update can be found in the *Demand-Side Management 2021 Annual Report, Supplement 1: Cost-Effectiveness.*

### 2023 Plans

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. Idaho Power has committed to a booth at the Idaho Irrigation Equipment Show & Conference, Western Ag Expo, Idaho Potato Show, and the Southern Ag Expo in 2023. The focus of the booth material and conversations will be to promote the Irrigation Efficiency Rewards program and what customers can do to obtain incentives from Idaho Power. Marketing the program to irrigation supply companies will continue to be a priority, as they are an important part of getting the program in front of customers.

The company will promote the program in agriculturally focused editions of newspapers, magazines, and radio ads. The radio ads will run during the winter/spring throughout the company's South-East region.

## Irrigation Peak Rewards

| | | 2022 | 2021 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (service points) | 2,142 | 2,235 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW)* | 155.1/255.6 | 255.5/319.5 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $569,467 | $239,101 |
| | Oregon Energy Efficiency Rider | $272,171 | $167,041 |
| | Idaho Power Funds | $7,661,502 | $6,607,173 |
| | Total Program Costs—All Sources | $8,503,140 | $7,013,315 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/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 |

* Maximum actual demand reduction/maximum potential demand reduction. Demand response program reductions are reported with 9.7% peak loss assumptions.

### Description

Idaho Power's Irrigation Peak Rewards program is a voluntary, demand response program available to all agricultural irrigation customers. Initiated in 2004, the purpose of the program is to minimize or delay the need for 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 and offers two interruption options: Automatic Dispatch Option and Manual Dispatch Option. Automatic Dispatch Option pumps are controlled by an AMI or 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. Manual Dispatch Option customers nominate a kW reduction and are compensated based on the actual load reduction during the event.

Program event parameters for both interruption options are listed below:

- June 15 to September 15 (excluding Sundays and holidays)
- Up to four hours per day between 3 and 10 p.m. (Standard Interruption) or 3 and 11 p.m. (Extended Interruption)
- Up to 16 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 payments are credits that are applied to the monthly billing during the months of June through October. The fixed credits are based on the customer's actual demand and use, and reduce the monthly billed amount. The variable payments are additional incentives that are paid beginning with the fifth event. The variable payments are calculated at the end of the season and are mailed to the customers in the form of a check.

The fixed incentive amount is $5.25 per kW with an energy incentive of $0.008 per kWh. The fixed incentive demand (kW) credit is calculated by multiplying the monthly billing kW usage by the fixed incentive amount. The energy (kWh) incentive credit is calculated by multiplying the monthly billing kWh usage by the energy incentive amount. The fixed 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 incentive of $0.18 (Standard Interruption) per kWh applies to the fifth and subsequent events that occur between 3 p.m. and 10 p.m. The variable incentive is increased to $0.25 per kWh when customers allow Idaho Power to interrupt their pumps for 4 hours between 3 p.m. and 11 p.m. For the Automatic Dispatch Option service points, the variable incentive is calculated using the billed demand (kW) during the billing cycle/period of the event, multiplied by the length of the event in hours multiplied by the applicable variable incentive rate. For the participating Manual Dispatch Option participants, the variable incentive payment is calculated based on the actual demand (kW) reduction during the event hours multiplied by the length of the event in hours multiplied by the applicable variable incentive rate. The variable incentive is paid in the form of a check no later than 70 days after the program season.

Program rules allow customers to opt out of dispatch events while incurring an opt-out fee of $6.25. The opt-out fee is calculated by multiplying $6.25 times the kW cost based on the current month's billing or kW not achieved for Manual Dispatch Option participants. The kW not achieved for the Manual Dispatch Option refers to the amount that was nominated versus the actual kW reduction that was achieved. At the start of the season the manual customers nominate the amount of kW reduction they plan to achieve during a demand response event. The opt-out penalties will not exceed the total credit that would have been paid with full participation.

### Program Activities

Changes to the program as authorized by the OPUC and the IPUC in 2022 included lengthening the season from August 15 to September 15; changing the event window to later in the evening; increasing the fixed and variable incentives; changing the threshold from three to four events for when the variable incentive is paid; and opening enrollment to all agricultural irrigation customers.

In 2022, Idaho Power enrolled 2,142 (10%) of the eligible service points in its service area in the program. The total billing demand of participating service locations was 346.3 MW versus 402.8 MW in 2021. The total maximum potential reduction (capacity) for the program was 255.6 MW in 2022 versus 319.5 MW in 2021. The key factor impacting the lower maximum capacity was participation concern over the later evening hours and labor issues in getting systems going again after events. Another factor was that during enrollment for the program the water supply forecast looked to be very low, so customers felt they would have less ability to make up for load reduction events.

A primary ongoing activity each year is maintaining communication and device failure identification and correction both pre-season and during the season. Device failure is affected by many things outside the company's control, from customer electrical panel or wiring issues to actual component failure in the device. The company used three electrical contractors in 2022 to maintain, troubleshoot, repair, and exchange the AMI devices and cellular devices that are attached to customers electrical panels to be able to turn pumps off during events.

Table 21 shows the event performance by date and group. The total load reduction shown in 2022 is less than 2021 because Idaho Power had a smaller number of total MW enrolled in the program in 2022. The program was used on eleven days. Nine days had two groups participating and two days had all four groups participating, for 43 total event hours. The program achieved an actual maximum demand reduction of 155.1 MW (at generation level) on September 2, with all groups participating.

**Table 21. Irrigation Peak Rewards demand response event details**

| Event Details | Thursday, July 7 | Tuesday, July 12 | Tuesday, July 26 | Wednesday, July 27 | Thursday, July 28 | Friday, July 29 | Monday, August 8 | Tuesday, August 9 | Wednesday, August 17 | Friday, September 2 | Tuesday, September 6 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Event Time (p.m.) | 6–10 | 4–9 | 4–9 | 5–10 | 4–9 | 4–10 | 3–9 | 4–9 | 4–10 | 3–10 | 6–10 |
| Groups | A, B | C, D | A, C | B, D | A, C | B, D | C, D | A, B | B, C | A, B, C, D | A, B, C, D |
| High Temperature* | 95° F | 101° F | 100° F | 102° F | 103° F | 104° F | 104° F | 99° F | 103° F | 101° F | 101° F |
| Maximum Load Reduction (MW) | 121.2 | 109.1 | 113.5 | 76.2 | 102.6 | 76.8 | 83.9 | 75.1 | 86.8 | 155.1 | 152.1 |

*National Weather Service, recorded in the Boise area

### Marketing Activities

New program parameters per IPUC Case IPC-E-21-32 and OPUC Docket No. ADV 1355/Advice No. 21-12 (replacing the IPC-E-13-14/UM 1653 Settlement agreement) went into effect in 2022 and allowed Idaho Power to market the program to all potential customers.

In 2022, the program brochures and website were updated to reflect the new program parameters. Idaho Power used virtual workshops, direct-mail, and outreach calls to encourage past participants to re-enroll in the program and potential new participants to enroll for the first time. The brochure, enrollment worksheet, and contact worksheet were mailed to all eligible participants in March 2022. See the Irrigation Sector Overview section for additional marketing activities.

### Cost-Effectiveness

Idaho Power determines cost-effectiveness for the demand response programs using the approved method for valuing demand response under IPUC Order No. 35336 and the OPUC's approval on February 8, 2022, in Docket No. ADV 1355. Using the financial and alternate resource cost assumptions from the *2021 Integrated Resource Plan,* the defined cost-effectiveness threshold for operating Idaho Power's three demand response programs for the maximum allowable 60 hours is $82.91 per kW under the current program parameters.

The Irrigation Peak Rewards participants were dispatched for either six or seven events, resulting in either 24 or 28 event hours and achieved a maximum demand reduction of 155.1 MW with a maximum potential capacity of 255.6 MW. The total expense for 2022 was $8.5 million and would have been approximately $10.5 million if the program had been operated for the full 60 hours. Using the potential cost and the maximum potential capacity results in a cost of $40.97 per kW, which shows the program was cost-effective.

A complete description of cost-effectiveness results for Idaho Power's demand response programs is included in *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction

In November, Idaho Power sent surveys to program participants and non-participants. The purpose of the surveys was to evaluate the motivators and barriers to participation as well as gauge customers' likelihood to participate in the program under varying program designs. Participants were asked additional questions around their customer's overall satisfaction with the program and the ease of participation.

Idaho Power received 93 responses from the participant survey and 171 responses from the non-participant survey. Some highlights include the following:

- For participants, nearly 42% of respondents indicated their irrigation system type and 20% indicated the time of event hours prevented them from enrolling additional irrigation service locations in the program. For non-participants, almost 14% of the respondents did not participate in the program because it's too much risk to their crops while 13% of respondents indicated it was too much trouble to coordinate their system/labor.

- More than 47% of participant survey respondents are enrolled in the Extended Interruption Option. Of those enrolled, 68% chose to participate because of the increased variable incentive.
- Overall, 75% of participant survey respondents indicated they are "very satisfied" or "somewhat satisfied" with the Peak Rewards program.
- Nearly 85% of participant survey respondent indicated they are "very likely" or "somewhat likely" to participate in the program in 2023.
- Respondents were asked their likelihood to participate in the program if Idaho Power limited the number of times the program could be called each week at a reduced incentive level.
    - Under all scenarios, 58 to 63% of current participants indicated they are "very unlikely" or "somewhat unlikely" to participate in the program under the proposed hypothetical scenario options.
    - Under all scenarios, 53 to 58% of current non-participants indicated they are "very unlikely" or "somewhat unlikely" to participate in the program under the proposed hypothetical scenario options.

A copy of the complete report is included in *Supplement 2: Evaluation.*

### Evaluations

Each year, Idaho Power produces an internal report of the Irrigation Peak Rewards program. This report includes more detail on the load-reduction analysis, overall costs, and program participation. A breakdown of the load reduction for each event day and each event hour, including line losses, is shown in Table 22.

**Table 22. Irrigation Peak Rewards program MW load reduction for events**

| Event Date | Groups* | 3–4 p.m. | 4–5 p.m. | 5–6 p.m. | 6–7 p.m. | 7–8 p.m. | 8–9 p.m. | 9–10 p.m. |
|---|---|---|---|---|---|---|---|---|
| 7/7/2022 | A, B | | | | 115.3 | 121.2 | 119.5 | 119.1 |
| 7/12/2022 | C, D | 5.5 | 67.1 | 109.1 | 108.9 | 101.1 | 40.5 | |
| 7/26/2022 | A, C | 3.1 | 68.5 | 113.5 | 113.5 | 108.7 | 43.0 | |
| 7/27/2022 | B, D | | | 42.2 | 75.8 | 76.2 | 75.8 | 32.5 |
| 7/28/2022 | A, C | 5.1 | 59.7 | 102.6 | 102.1 | 96.1 | 40.6 | |
| 7/29/2022 | B, D | | 40.4 | 40.5 | 76.2 | 76.8 | 35.5 | 35.0 |
| 8/8/2022 | C, D | 16.3 | 54.4 | 83.9 | 80.6 | 67.8 | 30.2 | |
| 8/9/2022 | A, B | | 40.1 | 74.0 | 75.1 | 74.6 | 33.7 | |
| 8/17/2022 | B, C | | 4.1 | 55.8 | 86.7 | 86.8 | 81.4 | 29.5 |
| 9/2/2022 | A, B, C, D | 4.5 | 43.7 | 117.7 | 155.1 | 147.3 | 110.2 | 37.5 |
| 9/6/2022 | A, B, C, D | | | | 102.8 | 122.7 | 151.0 | 152.1 |

*Group C had some customers on an early off time.

### 2023 Plans

For the 2023 program season, Idaho Power will continue the program as revised in 2022 as authorized by the IPUC and the OPUC.

Irrigation Peak Rewards enrollment packets will be sent to all irrigation customers. Each customer will be sent a comprehensive packet containing an informational brochure, enrollment worksheet and a contact worksheet. For all new pump signups, a demand response unit will need to be installed by a contracted electrician prior to June 15, 2023.

Idaho Power will have an informational booth at the local 2023 Ag Expos including Western, Eastern, and Southern. The Irrigation Peak Rewards program will be the focus of in person workshops presented by Idaho Power ag reps in spring 2023. For the upcoming season, Idaho Power will continue its focus on retaining currently enrolled participants and will consider using email marketing, radio, paid search, digital display, and other new tactics to boost program enrollment. The ag reps will continue to remind and inform customers and encourage program participation in person and by phone.

# Other Programs and Activities

## *Idaho Power's Internal Energy Efficiency Commitment*

Renovation projects continued at the Idaho Power Corporate Headquarters (CHQ) in downtown Boise, with a project to exchange the old T-12 parabolic lighting fixtures with LED fixtures on floors five, six and seven. Remodels continued to incorporate energy efficiency measures, such as lower partitions for better transfer of daylight, transom lighting, and automated lighting controls.

The CHQ building also participated in the Flex Peak Program again in 2022 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.

## *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. Because 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, there has been minimal participation in the LEEF offering.

In 2022, Idaho Power received seven LEEF applications. They were generally related to home equipment replacement requests for items such as windows, heating systems, door seals, and load centers. The applications were reviewed, and the products referenced in the submittals were found to be standard, widely available products, and therefore not appropriate for LEEF. A residential program specialist followed up with the applicants to provide information on incentives currently available through Idaho Power's H&CE Program.

## *Energy Efficiency Advisory Group (EEAG)*

Formed in 2002, EEAG provides input on enhancing existing DSM programs and on implementing energy efficiency programs. Currently, EEAG consists of 12 members representing a cross-section of Idaho Power customers from the residential, industrial, commercial, and irrigation sectors, as well as individuals representing low-income households, environmental organizations, state agencies, city governments, public utility commissions, and Idaho Power.

EEAG meets quarterly, and when necessary, Idaho Power facilitates additional meetings and/or calls to address special topics. In 2022, four regular virtual EEAG meetings were held on February 9, May 4, August 11, and November 17. 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 programs and expenses, gave updates of ongoing programs and projects, and supplied general information on DSM issues and other important issues occurring in the region.

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 programmatic changes, marketing tactics, and incentive levels.

Throughout 2022, Idaho Power relied on input from EEAG on the important topics discussed in the sections below. For complete meeting notes, see *Supplement 2: Evaluation*.

## *Market Transformation*

Idaho Power's energy efficiency programs and activities are gradually transforming markets by changing customers' 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 and Avista Utilities continued working with a third-party marketing firm on a project that began in 2020 to explore potential opportunities to accelerate market transformation; the goal is to benefit customers in both utilities' service areas beyond what NEEA is currently providing. This work resulted in a market transformation pilot that began in 2021 for DHPs in both Idaho Power's and Avista's service areas. The pilot was active throughout 2022 and will continue through 2023.

### 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.

Idaho Power participates in NEEA with funding from the Idaho and Oregon Riders. The current NEEA contract is for the five years from 2020 to 2024. NEEA categorizes the savings 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 to 500 average megawatts (aMW) of savings forecast for 2020 to 2024, NEEA expects 70 to 100 aMW to be net market effects, and 115 to 152 aMW to be co-created savings. The current contract commits Idaho Power to paying NEEA a total of $14.7 million, or approximately $2.9 million annually.

In 2022, Idaho Power participated in all NEEA 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, Regional Emerging Technology Advisory Committee (RETAC) and the Idaho Energy Code Collaborative. The company also participated in NEEA's initiatives, including the Commercial Building Stock Assessment (CBSA), Residential Building Stock Assessment (RBSA), SEM, Top-Tier Trade Ally (NXT Level), and Luminaire Level Lighting Controls (LLLC).

NEEA performed several market progress evaluation reports (MPER) on various energy efficiency efforts this year. In addition to the MPER, NEEA provides market research reports through third-party contractors for energy efficiency initiatives throughout the Northwest. Links to these and other reports mentioned below are provided in *Supplement 2: Evaluation* and on NEEA's website under Resources & Reports. For information about all committee and workgroup activities, see the NEEA Activities information below.

### NEEA Marketing

To support NEEA efforts, Idaho Power educated residential customers on Heat Pump Water Heater (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. Full details can be found in the H&CE Program's Marketing section.

The company participated in NEEA's HPWH *Boring but Efficient* campaign that ran on digital channels from September 1–October 31 to continue increasing consumer awareness. The advertising directs customers to visit their local utility's website, find a local installer, locate a retailer, and get product information from manufacturers.

Idaho Power continued to encourage trade allies to take the NXT Level Lighting Training. Idaho Power posted NXT Level Lighting Training information on its website and on LinkedIn in May.

To promote LLLC, Idaho Power continued using a link to an informational LLLC flyer on its main Retrofits and Lighting web pages. The company also posted about LLLCs on LinkedIn in May.

### NEEA Activities: All Sectors

For the 2020 to 2024 funding cycle, NEEA and its funders have reorganized the advisory committees into two coordinating committees: Products Coordinating Committee and Integrated Systems Coordinating Committee. Additionally, NEEA and its funders form working groups as needed in consultation with the RPAC. The RPAC will continue, as well as the Cost-Effectiveness Advisory and the RETAC committees. The Idaho Energy Code Collaborative will also remain intact.

The company currently has representation on both of the NEEA coordinating committees. Quarterly meetings were held in 2022 for both committees. These committees provide utilities with the opportunity to give meaningful input into the design and implementation of NEEA initiatives, as well as to productively engage with each other. Working groups were formed by the coordinating committees to focus on topics relevant to all sectors, as described below.

#### *Cost-Effectiveness and Evaluation Advisory Committee*

The advisory committee 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 International Energy Conservation Code (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. NEEA facilitates the group, 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 educates the building community and stakeholders to increase energy code knowledge and compliance. Idaho Power is an active member.

The Idaho Energy Code Collaborative provided statewide resources throughout 2022 to builders and related stakeholders in support of the current codes. The resources included monthly training sessions, a monthly technical newsletter by email, and a robust website—IdahoEnergyCode.com. Idaho Power will continue to participate in the Idaho Energy Code Collaborative.

#### *Regional Emerging Technology Advisory Committee (RETAC)*

Idaho Power participated in the RETAC, which met quarterly to review RETAC's emerging technology pipeline that was developed with assistance from the BPA, NEEA, and the NWPCC. Throughout 2022, RETAC focused primarily on space-heating and water-heating products for residential and commercial markets. The technologies for these products centered on heat pumps. RETAC discussed the current state of the technologies and their associated gaps and issues. In each RETAC session, the group discussed ways NEEA and the regional utilities could help address those gaps and issues. This work will continue in 2023.

#### *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 2022, RPAC conducted three of the quarterly meetings, all of which were virtual; the November meeting was cancelled as topics were not time-sensitive and could wait until 2023. Throughout 2022, RPAC received updates of savings forecasts, portfolio priorities, and committee reports.

In the first regular quarterly meeting on February 23, NEEA staff went over upcoming milestones for the NEEA initiatives and presented charter and various work group updates. Upcoming milestone votes NEEA reviewed were: Efficient Fans, Extended Motor Products for Pumps, High Performance HVAC, High Performance Windows, and Variable-speed Heat Pumps. NEEA staff made the committee aware of the details involved in program advancement and went over the timeline for each initiative.

On May 25, NEEA staff updated RPAC on recent developments and reviewed the NEEA electric portfolio, reminding RPAC members of the key portfolio goals, programs included, current status in NEEA's initiative lifecycle, savings and risk profiles, and which programs help with portfolio diversification. NEEA provided an overview on the Extended Motor Products—Pumps and Circulators program in preparation for a committee vote to move the initiative to the next phase of market development; the committee voted to approve that action. NEEA provided an update on both the High-Performance HVAC program and Efficient Fans program based on an anticipated milestone vote to advance each next quarter. NEEA staff also went over a proposal to run the 2021 HPWH ad campaign again in September through October 2022.

At the August 24 meeting, NEEA gave RPAC members a portfolio update showing status and outlook of each initiative. NEEA provided an overview on the Efficient Fans program in preparation for a committee vote to move the initiative from concept development to program development; the committee voted to approve that action. NEEA also presented the High-Performance HVAC program in preparation for a committee vote to move the initiative to the next phase of market development; the committee voted to approve that action. NEEA also presented their 2023 Operations Plan and timeline.

### NEEA Activities: Residential

NEEA provides BetterBuiltNW online builder and contractor training and manages the regional homes database, AXIS.

#### *Residential Building Stock Assessment (RBSA)*

The RBSA is a study 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 the NWPCC to determine load forecast and energy-savings potential in the region. NEEA began work on the RBSA in mid-2020.

Idaho Power participated in monthly work group meetings to discuss the study's objectives, framework, sampling design, and communication plan. Site visits in the region began at the end of 2021 and continued through 2022. For residential customers who chose to participate, the third-party contractor scheduled a site visit with a field technician who collected information on the home's characteristics. While site visits for single-family homes are now complete, NEEA continues to recruit for multifamily buildings to participate in the study. Field work will continue through early quarter 2 of 2023.

Due to delays in receiving the demographic and housing characteristics file from the 2020 U.S. Census, completion of the study has been delayed. A final report will be available by the end of 2023.

### NEEA Activities: Commercial/Industrial

NEEA continued to provide support for C&I energy efficiency activities in Idaho in 2022, which included partial funding of the IDL for trainings and additional tasks.

#### *Commercial Building Stock Assessment (CBSA)*

NEEA began work on the CBSA in 2022. The CBSA is a study conducted approximately every five years, and the information is used by utilities in the Pacific Northwest and the NWPCC to determine load forecast and electrical energy-savings potential in the region.

For commercial customers who chose to participate in the study, the third-party contractor scheduled a site visit with a field technician who collects information on equipment and building characteristic that affect energy consumption. This includes HVAC equipment, lighting, building envelope, water heating, refrigeration and cooking, computers and miscellaneous equipment, and cooling towers.

Beginning in August 2022, Idaho Power staff participated in the monthly working group. The CBSA is still in the early design phase of the study, thus the objectives and priorities are still being determined. A request for proposal to select a contractor will be issued in early 2023 with site visits planned for 2024 through 2025. The report is slated to be released in early 2026.

##### *Very High-Efficiency Dedicated Outside Air Systems (DOAS)*

NEEA's High-Performance HVAC program focused on design of market intervention strategies based on market and field research associated with very high efficiency DOAS. Very high-efficiency DOAS pairs a very high-efficiency heat/energy recovery ventilator (HRV/ERV) type of DOAS with a high-efficiency heating and cooling system, while following set design principles that maximize efficiency. NEEA updated the Very High Efficiency DOAS system requirements in 2022 based on market feedback and project experience. NEEA performed market research and published a report titled *VHE DOAS Commercial Building Decision Makers Market Research* on March 29, 2022, on building owners' perceptions of the challenges and benefits of very high efficiency DOAS. NEEA also created additional resources for utilities provided on the BETTERBRICKS website.

##### *Luminaire Level Lighting Controls (LLLC)*

Throughout 2022, NEEA engaged with key manufacturers and their sales channels to encourage promotion of LLLC to their customers and projects. NEEA continued to partner with utilities to offer trade ally training opportunities for awareness and increased understanding of Networked Lighting Controls (NLC)/LLLC systems. Two of the training classes were held in Idaho Power's service area, with 38 trade allies receiving NLC/LLLC training.

NEEA continued to offer a variety of LLLC educational resources for use by utilities and their customers and trade allies. These materials are found at betterbricks.com. In addition, NEEA is actively working with utilities in the Pacific Northwest to develop case studies of commercial buildings that incorporated LLLC.

### NEEA Funding

In 2020, Idaho Power and NEEA commenced a five-year agreement for the 2020 to 2024 funding cycle. Per this agreement, NEEA implements market transformation programs in the company's service area and 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. On February 20, 2020, Idaho Power received IPUC Order No. 34556, supporting Idaho Power's participation in NEEA from 2020 to 2024 with such participation to be funded through the Idaho Rider and subject to a prudency review.

In 2022, Idaho Power paid $2,789,937 to NEEA: $2,650,440 from the Idaho Rider for the Idaho jurisdiction and $139,497 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 the Idaho and Oregon Riders.

Final NEEA savings for 2022 will be released later in 2023. Preliminary estimates reported by NEEA indicate Idaho Power's share of regional market transformation savings as 24,448 MWh. These savings are reported in two categories: 1) codes-related and standards-related savings of 20,344 MWh (83%) and 2) non-codes-related and non-standards-related savings of 4,104 MWh (17%).

The preliminary savings reported by NEEA for 2022 had one change in methodology. Because code adoption varies between states, NEEA transitioned to report energy savings for state building codes using a state allocation approach, as the funder share allocation methodology no longer provided a reasonable representation of code savings occurring in a funder's service area. For non-codes related savings, NEEA continued to use the funder share allocation methodology. Idaho Power has requested that non-codes savings use the service area allocation approach. NEEA has committed to work with Idaho Power in 2023 to update the assumptions used to allocate savings before shifting to this methodology for 2023 reporting.

In the *Demand-Side Management 2021 Annual Report*, preliminary funding-share estimated savings reported were 17,870 MWh. The final funding-share NEEA savings for 2021 reported herein are 16,819 MWh, and 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 at 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 regarding the following RTF charter items:

- 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 2022, Idaho Power staff participated in all RTF meetings as a voting member and is represented on 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 2022.

## *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 2022. Idaho Power's Customer Care 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. It was promoted in the 2022 *Energy Efficiency Guide*, and on the fall energy efficiency bill insert, which went to all residential customers in September. The meter was also demonstrated and promoted during the October KTVB segment.


**Figure 23. Energy Efficiency Kit featuring the Kill A Watt meter**

### Customer Education and Marketing

REEEI produced one *Energy Efficiency Guide* in 2022, which was distributed primarily as an insert in local newspapers. The year-round-themed guide was published and distributed by the *Boise Weekly* and 24 newspapers in Idaho Power's service area the week of June 26. The guide focused on information that would be useful to customers throughout the year, including energy-savings 101, what a kilowatt is and how customers can use a Kill A Watt meter to measure watts, tips for working with a contractor, how to find information about energy savings, ways to save energy during each season, an energy efficiency success story, the A/C Cool Credit program, and information for customers considering rooftop solar.

Idaho Power promoted the guide on its homepage, on social media, and through a link emailed to residential customers. The *Idaho Statesman* published two ads encouraging readers to look for the guide. Digital ads on idahostatesman.com included a homepage takeover on June 26 and June 30, as well as banner ads that ran between June 26 and July 9, earning 150,000 impressions. Digital ads drove traffic to the *Energy Efficiency Guide* on idahopower.com.

Idaho Power's website also provides links to the current guide, as well as past seasonal guides. In 2022, over 184,000 guides were distributed throughout the service area.

REEEI distributed energy efficiency messages through a variety of other communication methods in 2022. 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 2022, the program distributed 1,550 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 energy efficiency program specialists connected with energy advisors and other employees from each of Idaho Power's geographical regions and the Customer Care Center to discuss educational initiatives and answer questions about the company's energy efficiency programs.

As COVID-19 concerns waned, opportunities to re-engage with customers at in-person community events and venues began to return to normal. Idaho Power participated in 42 events highlighting energy efficiency messages. Program specialists and EOEAs shared information about programs and other energy-saving ideas in an additional 667 presentations and trainings for audiences of all ages throughout the year. To increase opportunities with adult audiences and more secondary-school-aged young people, the EOEAs carried out a concerted marketing effort—establishing relationships with 338 new influencers and decision-makers. Additionally, Idaho Power's energy efficiency program specialists responded with detailed answers to 375 customer questions about energy efficiency and related topics that were either forwarded from the Idaho Power's Customer Care Center or received via Idaho Power's website.

Idaho Power's social media channels and *News Briefs* focused on content designed to help customers save energy, including quarterly bill inserts and emails that provided all residential customers with easy steps to get their home ready for each season, and behavioral tips for reducing energy use.

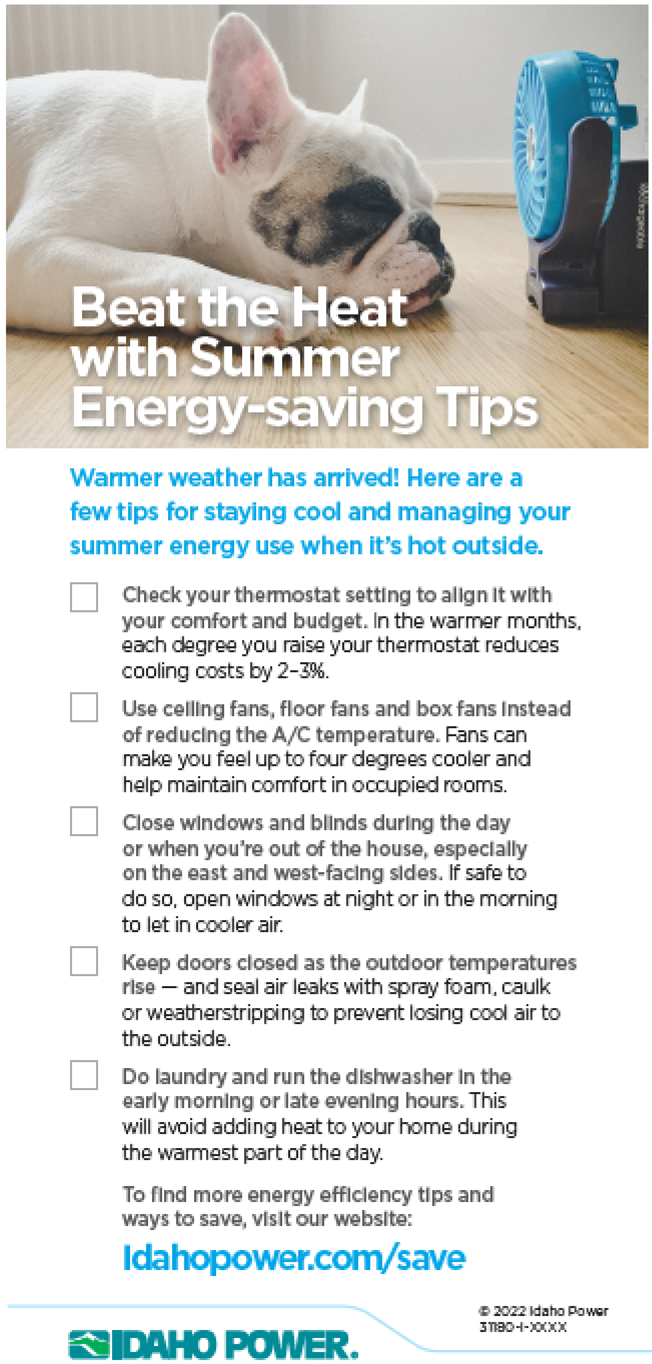



**Figure 24. Summer energy-saving tips**

Idaho Power promoted National Energy Awareness Month on social media in October. *News Briefs* and the regular KTVB television spots also highlighted Energy Awareness Month activities.

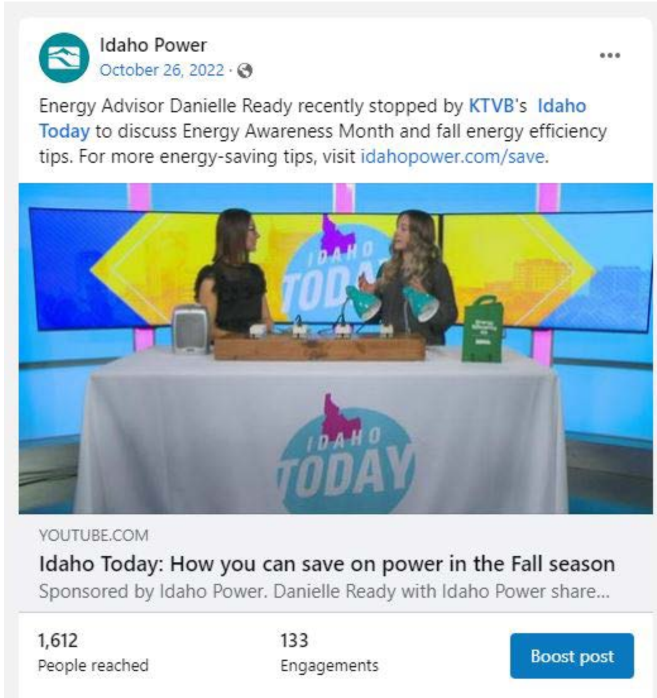



**Figure 25. Energy Awareness Month social media posts**

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 news segments focusing on energy efficiency.

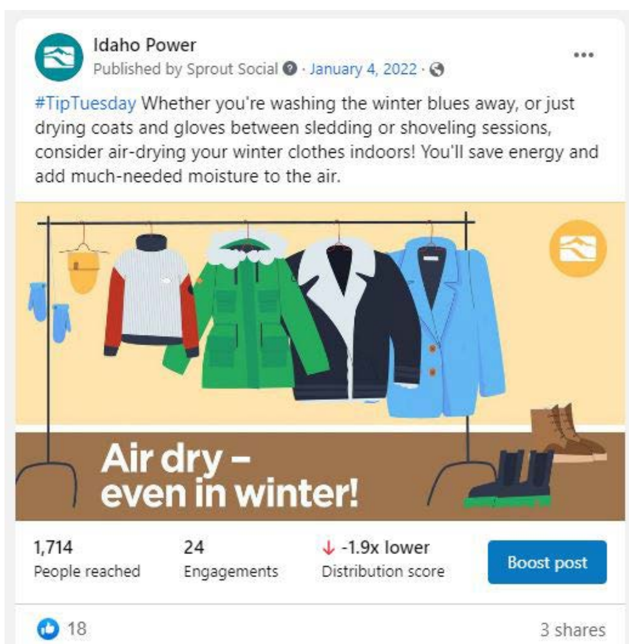



**Figure 26. Tip Tuesday post**

### 2023 Program and Marketing Strategies

The initiative's 2023 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, and distributing welcome kits.

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.

## *Distributed Energy Resources*

Pursuant to Order Nos. 32846 and 32925 in Case No. IPC-E-12-27 and Order No. 34955 in Case No. IPC-E-20-30, Idaho Power files its annual *Distributed Energy Resources (DER) Status Report* with the IPUC in April each year. The report provides updates on participation levels of customer generation, system reliability considerations, and accumulated excess net energy credits. The report can be accessed on Idaho Power's website (idahopower.com/solar); links to the three most recent reports are located to the right on the web page, in the section labeled *DER/Customer Generation Status Reports*.

## *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 2022, Idaho Power entered into an agreement with the IDL to perform the tasks and services described below.

### Foundational Services

The goal of this task is 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

The IDL provided technical assistance on 16 new projects in Idaho Power's service area in 2022: 12 Phase I projects, three Phase II projects, and one Phase III project. Ten of the projects were on new buildings, five were on existing buildings, and one was general design assistance. The number of projects were the same compared to 2021. The related report is in the IDL section of *Supplement 2: Evaluation*.

#### Lunch & Learn

The goal of the Lunch & Learn task is to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions.

In 2022, the IDL provided 14 in-person technical training lunches. A total of 100 architects, engineers, designers, project managers, and others attended.

The topics of the lunches (and the number performed of each) were: Ultraviolet Germicidal Air Irradiation (1); Daylighting Multipliers (1); Thermal Energy Storage Systems (1); LLLC (3); High-Performance Classrooms (1); The Future of Lighting Controls (3); Dedicated Outdoor Air Systems (DOAS) Integration (1); LED Technology Impact on Savings and Efficiency (1); LEED V4.1 Daylighting Credits (1); and ASHRAE 36 High Performance Sequence of Operations for HVAC Systems (1). The related report is in the IDL section of *Supplement 2: Evaluation*.

#### Building Simulation Users Group (BSUG)

The goal of this task is to facilitate the Idaho BSUG, which is designed to improve the energy efficiency related simulation skills of local design and engineering professionals.

In 2022, six BSUG sessions were hosted by the IDL. Three of the six sessions were hosted in person and three were hosted virtually due to COVID-19 restrictions at the time. The sessions were attended by 195 professionals. Evaluation forms were completed by attendees for each session. Analyzing results from the first six questions that rated the sessions on a scale of 1 to 5, with 5 being "excellent" and 1 being "poor," the average session rating was 4.37 for 2022. 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 3.23 for 2022.

Each presentation was archived for remote access anytime, along with general BSUG content through the IDL website. The related report is in the IDL section of *Supplement 2: Evaluation*.

#### New Construction Verification

The goal of this task is to provide random on-site project verification on approximately 10% of the total completed C&I Energy Efficiency Program New Construction projects. This task also includes the desk review of all daylight photo-control incentives to improve the quality of design and installation.

In 2022, Idaho Power collaborated with IDL to create a new process for on-site verification to ensure that the final project documentation aligns with field installation prior to project payment. IDL conducted eight random on-site, project verifications. The purpose of these verifications was to confirm accurate information was provided regarding measure installations. The complete verification report is in the IDL section of *Supplement 2: Evaluation*.

#### Energy Resource Library (ERL)

The ERL gives customers access to resources for measuring and monitoring energy use on various systems. The goal of this task is 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 2022, 69 new tools were added to replace old data logging models, current transformers, air quality sensors to complete tool kits, and added accessories for kits. 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 is available if desired.

In 2022, nine of the 16 tool loan requests were completed by six unique users from seven locations, including two new users. Two additional loan requests are ongoing. The ERL web page recorded 2,768 visits compared to 1,483 visits in 2021. The related report is in the IDL section of *Supplement 2: Evaluation*.

#### Power over Ethernet (PoE)

In 2022, the IDL completed a literature review of the PoE technology and how it compares to conventional lighting technology. PoE can be configured to work with many low-wattage LEDs and can be addressed by Internet Protocol (IP) for individual control resulting in energy savings. The IDL met with several facility managers and reached out to architects, engineers, and consultants to find a suitable case study site. Due to project costs and installation time and effort, a site was not discovered to use for this task. The related report for this task is in the IDL section of *Supplement 2: Evaluation*.

#### Luminaire Level Lighting Controls (LLLC) Workshop Development

In 2022, the IDL planned and organized one LLLC workshop which consisted of a one-hour classroom presentation and a one-hour hands-on demonstration. Ten industry professionals attended the presentation and demonstration. The IDL installed LLLCs in their open office area and configured them into daylighting and occupancy zones. The related report for this task is in the IDL section of *Supplement 2: Evaluation*.

### Design Tools Update

Over the years, the IDL has developed several digital design tools to assist local firms. These tools require updating over time. In 2022, 12 tools were hosted on the IDL website and made available for use and download serving as a one-stop resource for engineers and architects for early design considerations. IDL provided priority for each tool and will update in future tasks. The related report for this task is in the IDL section of *Supplement 2: Evaluation*.

### 2023 IDL Strategies

In 2023, the IDL will continue work on Foundational Services, Lunch & Learn sessions, BSUG, New Construction Verifications, ERL, Design Tools Update and one new task, Fan Savings UV Lamps.

# CONCLUSIONS

This DSM report provides a summary of activities performed by Idaho Power to offer DSM programs to all its customers throughout 2022. All Programs are generally designed to educate, inform, and/or reward customers.

The savings from energy efficiency programs, including the estimated savings from NEEA, were 169,889 MWh, and the energy efficiency portfolio was cost-effective from all three benefit/cost methodologies (UCT, TRC, and PCT).

Idaho Power successfully operated its three demand response programs in 2022, with total demand response capacity approximately 312 MW and an actual max load reduction of 200 MW.

The DSM programs are carefully managed and monitored for ways to improve savings, cost-effectiveness, and value to the customer. Two energy efficiency programs were closed in 2022 and three energy efficiency programs are being phased out in 2023, either because rising costs have impacted cost-effectiveness or because market trends have lessened the impact of the offerings and measures.

Idaho Power's collaboration with multiple stakeholders lays the groundwork for building a more energy efficient future with the long-term goal of permanently changing the existing market for energy-efficient equipment and practices.

This *DSM 2022 Annual Report* satisfies the reporting obligation set forth by IPUC Order No. 29419 in Case No. IPC-E-03-19.

# LIST OF ACRONYMS

A/C—Air Conditioning or Air Conditioner

Ad—Advertisement

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

AHRI—Air-Conditioning, Heating, and Refrigeration Institute

ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers

ASHP—Air-Source Heat Pumps

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

BSU—Boise State University

BSUG—Building Simulation Users Group

BTU—British Thermal Units

C&I—Commercial and Industrial

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CBSA— Commercial Building Stock Assessment

CCNO—Community Connection of Northeast Oregon, Inc.

CCS—Commissioning, Sizing, and Controls

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CFM—Cubic Feet per Minute

CHQ—Corporate Headquarters (Idaho Power)

CIEE—Commercial and Industrial Energy Efficiency

CINA—Community in Action

COP—Coefficient of Performance

CR&EE—Customer Relations and Energy Efficiency

CSA–Customer Solutions Advisors

CSI—College of Southern Idaho

DHP—Ductless Heat Pump

DOAS—Dedicated Outside Air Systems

DOE—US Department of Energy

DR—Demand Response

DSM—Demand-Side Management

EA5—EA5 Energy Audit Program

ECM—Electronically Commutated Motor

EEAG—Energy Efficiency Advisory Group

EEI—Edison Electric Institute

EICAP—Eastern Idaho Community Action Partnership

EISA—*Energy Independence and Security Act of 2007*

EIWC—Eastern Idaho Water Cohort

EL ADA—El Ada Community Action Partnership

EM&V—Evaluation, Measurement, and Verification

EPA—Environmental Protection Agency

EOEA—Education and Outreach Energy Advisors

ERL—Energy Resource Library

ERV— Recovery Ventilator

ESK—Energy-Saving Kit

ETO—Energy Trust of Oregon

ft—Feet

GMI—Green Motors Initiative

GMPG—Green Motors Practice Group

GWh–Gigawatt-hour

H&CE—Heating & Cooling Efficiency

HER—Home Energy Report

HOU—Hours of Use

hp—Horsepower

HPWH—Heat Pump Water Heater

HRV—Heat Recovery Ventilator

HSPF—Heating Seasonal Performance Factor

HUD—Housing and Urban Development

HVAC—Heating, Ventilation, and Air Conditioning

IAQ—Indoor Air Quality

IBCA—Idaho Building Contractors Association

IBCB—Idaho Building Code Board

ID—Idaho

IDHW—Idaho Department of Health and Welfare

IDL—Integrated Design Lab

IECC—International Energy Conservation Code

IP—Internet Protocol

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

ISM—In-Stadium Marketing

ISR—In-Service Rate

ISU—Idaho State University

kW—Kilowatt

kWh—Kilowatt-hour

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

LLLC—Luminaire Level Lighting Controls

M&V—Monitoring and Verification

MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association

MW—Megawatt

MWh—Megawatt-hour

n/a—Not Applicable

NEB—Non-Energy Benefit

NEEA—Northwest Energy Efficiency Alliance

NEEC—Northwest Energy Efficiency Council

NEEM—Northwest Energy-Efficient Manufactured Housing Program

NEMA—National Electrical Manufacturers Association

NLC—Networked Lighting Controls

NPR—National Public Radio

NREL—National Renewable Energy Laboratory's

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

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RBSA—Residential Building Stock Assessment

RCT—Randomized Control Trial

REEEI—Residential Energy Efficiency Education Initiative

REM—Required Energy Modeling

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

RTF—Regional Technical Forum

SAS—Statistical Analysis System

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

SIR—Savings-to-Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

TRC—Total Resource Cost

TRM—Technical Reference Manual

TSV—Thermostatic Shower Valve

UCT—Utility Cost Test

VFD—Variable Frequency Drive

WAP—Weatherization Assistance Program

WAQC—Weatherization Assistance for Qualified Customers

WSOC—Water Supply Optimization Cohort

WWEEC—Wastewater Energy Efficiency Cohort

# APPENDICES

## Appendix 1. Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December 2022)

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2022 Beginning Balance | $ | (6,937,705) |
| 2022 Funding plus Accrued Interest as of December 31, 2022 | | 34,843,936 |
| **Total 2022 Funds** | | **27,906,231** |
| 2022 Expenses as December 31, 2022 | | (31,673,550) |
| **Ending Balance as of December 31, 2022** | **$** | **(3,767,319)** |
| **Oregon Energy Efficiency Rider** | | |
| 2022 Beginning Balance | $ | (683,982) |
| 2022 Funding plus Accrued Interest as of December 31, 2022 | | 2,123,512 |
| **Total 2022 Funds** | | **1,439,530** |
| 2022 Expenses as of December 31, 2022 | | (1,285,478) |
| **Ending Balance as of December 31, 2022** | **$** | **154,052** |
| **NEEA Payments** | | |
| 2022 NEEA Payments as of December 31, 2022 | $ | 2,789,937 |
| **Total** | **$** | **2,789,937** |

**Appendix 2. 2022 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 | $ 429,722 | $ 24,491 | $ 375,558 | $ 829,771 |
| Easy Savings: Low-Income Energy Efficiency Education | — | — | 152,718 | 152,718 |
| Educational Distributions | 1,061,898 | 24,866 | 49 | 1,086,813 |
| Energy Efficient Lighting | 505,430 | 29,475 | 76 | 534,982 |
| Energy House Calls | 36,734 | 1,378 | 51 | 38,163 |
| Heating & Cooling Efficiency Program | 636,597 | 28,960 | 459 | 666,016 |
| Home Energy Audit | 184,650 | 0 | 208 | 184,858 |
| Home Energy Reports | 964,709 | — | 82 | 964,791 |
| Multifamily Energy Savings Program | 32,634 | 1,474 | 72 | 34,181 |
| Oregon Residential Weatherization | — | 8,825 | — | 8,825 |
| Rebate Advantage | 157,746 | 9,762 | 115 | 167,622 |
| Residential New Construction Program | $236,962 | (1,356) | 126 | 235,732 |
| Shade Tree Project | 128,673 | — | 183 | 128,856 |
| Weatherization Assistance for Qualified Customers | — | — | 1,281,495 | 1,281,495 |
| Weatherization Solutions for Eligible Customers | 198,198 | — | 7,590 | 205,788 |
| **Commercial/Industrial** | | | | |
| Commercial and Industrial Energy Efficiency Program | | | | |
| Custom Projects | 8,753,084 | 164,248 | 2,595 | 8,919,927 |
| New Construction | 2,762,412 | 17,582 | 513 | 2,780,507 |
| Retrofits | 4,785,645 | 84,933 | 337 | 4,870,916 |
| Commercial Energy-Saving Kits | 21,604 | 1,140 | 25 | 22,770 |
| Flex Peak Program | 84,582 | 151,148 | 283,888 | 519,618 |
| Small Business Direct Install | 1,317,820 | 27,558 | 51 | 1,345,429 |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 1,950,122 | 74,622 | 55,284 | 2,080,027 |
| Irrigation Peak Rewards | 569,467 | 272,171 | 7,661,502 | 8,503,140 |
| **Energy Efficiency/Demand Response Total** | **$ 24,818,689** | **$ 921,277** | **$ 9,822,976** | **$ 35,562,943** |
| **Market Transformation** | | | | |
| NEEA | 2,650,440 | 139,497 | — | 2,789,937 |
| **Market Transformation Total** | **$ 2,650,440** | **$ 139,497** | **$ —** | **$ 2,789,937** |
| **Other Programs and Activities** | | | | |
| Commercial/Industrial Energy Efficiency Overhead | 826,911 | 44,184 | 2,383 | 873,477 |
| Energy Efficiency Direct Program Overhead | 296,204 | 15,653 | 895 | 312,752 |
| Oregon Commercial Audit | — | 7,493 | — | 7,493 |
| Residential Energy Efficiency Education Initiative | 287,839 | 10,654 | 1,682 | 300,175 |
| Residential Energy Efficiency Overhead | 1,528,355 | 80,573 | 728 | 1,609,656 |
| **Other Programs and Activities Total** | **$ 2,939,309** | **$ 158,556** | **$ 5,689** | **$ 3,103,553** |
| **Indirect Program Expenses** | | | | |
| Energy Efficiency Accounting & Analysis | 1,236,470 | 64,628 | 175,865 | 1,476,963 |
| Energy Efficiency Advisory Group | 15,575 | 826 | 20 | 16,421 |
| Local Energy Efficiency Funds | — | — | — | — |
| Special Accounting Entries | 13,068 | 694 | — | 13,762 |
| **Indirect Program Expenses Total** | **$ 1,265,112** | **$ 66,148** | **$ 175,886** | **$ 1,507,146** |
| **Grand Total** | **$ 31,673,550** | **$ 1,285,478** | **$ 10,004,551** | **$ 42,963,579** |

**Appendix 3. 2022 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 | 19,127 | homes | $ 829,771 | $ 829,771 | n/a | 20.1/26.8 | n/a | n/a | n/a |
| Flex Peak Program | 159 | sites | 519,618 | 519,618 | n/a | 24.5/30.0 | n/a | n/a | n/a |
| Irrigation Peak Rewards | 2,142 | service points | 8,503,140 | 8,503,140 | n/a | 155.1/255.6 | n/a | n/a | n/a |
| **Total** | | | **$ 9,852,529** | **$ 9,852,529** | | **199.7/312.4** | | | |
| **Energy Efficiency** | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Easy Savings: Low-Income Energy Efficiency Education | 267 | HVAC tune-ups | 152,718 | 152,718 | 22,755 | | 5 | 1.448 | 1.448 |
| Educational Distributions | 49,136 | kits/giveaways | 1,086,813 | 1,086,813 | 3,741,954 | | 10 | 0.037 | 0.037 |
| Energy Efficient Lighting | 370,739 | lightbulbs | 534,982 | 714,445 | 1,728,352 | | 15 | 0.030 | 0.040 |
| Energy House Calls | 52 | homes | 38,163 | 38,163 | 54,516 | | 18 | 0.062 | 0.062 |
| Heating & Cooling Efficiency Program | 1,080 | projects | 666,016 | 2,414,026 | 1,310,260 | | 15 | 0.050 | 0.180 |
| Home Energy Audit | 425 | audits | 184,858 | 239,783 | 28,350 | | 11 | 0.771 | 1.000 |
| Home Energy Report Program[2] | 104,826 | treatment size | 964,791 | 964,791 | 20,643,379 | | 1 | 0.044 | 0.044 |
| Multifamily Energy Savings Program | 97 [3] | units [buildings] | 34,181 | 34,181 | 41,959 | | 11 | 0.096 | 0.096 |
| Oregon Residential Weatherization | 7 | audits/projects | 8,825 | 8,825 | 0 | | 45 | n/a | n/a |
| Rebate Advantage | 97 | homes | 167,622 | 402,649 | 255,541 | | 44 | 0.043 | 0.104 |
| Residential New Construction Program | 109 | homes | 235,732 | 578,922 | 337,562 | | 58 | 0.045 | 0.110 |
| Shade Tree Project | 1,874 | trees | 128,856 | 128,856 | 39,595 | | 40 | 0.218 | 0.218 |
| Weatherization Assistance for Qualified Customers | 147 | homes/non-profits | 1,281,495 | 2,028,513 | 272,647 | | 30 | 0.338 | 0.535 |
| Weatherization Solutions for Eligible Customers | 27 | homes | 205,788 | 205,788 | 48,233 | | 30 | 0.307 | 0.307 |
| **Sector Total** | | | **$ 5,690,839** | **$ 8,998,473** | **28,252,103** | | **5** | **$ 0.043** | **$0.068** |
| **Commercial/Industrial** | | | | | | | | | |
| Commercial Energy-Saving Kits | 334 | kits | 22,770 | 22,770 | 48,758 | | 10 | 0.059 | 0.059 |
| Custom Projects | 106 | projects | 8,919,927 | 25,715,468 | 56,157,060 | | 13 | 0.017 | 0.049 |
| Green Motors—Industrial | 9 | motor rewinds | | 3,424 | 19,851 | | 8 | | |
| New Construction | 88 | projects | 2,780,507 | 3,641,930 | 27,615,777 | | 12 | 0.011 | 0.015 |
| Retrofits | 525 | projects | 4,870,916 | 13,402,016 | 22,890,678 | | 12 | 0.024 | 0.065 |
| Small Business Direct Install | 680 | projects | 1,345,429 | 1,345,429 | 3,228,365 | | 11 | 0.049 | 0.049 |
| **Sector Total** | | | **$ 17,939,548** | **$ 44,131,037** | **109,960,489** | | **12** | **$ 0.018** | **$ 0.045** |

| 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 | 6 motor rewinds | | $ 5,634 | 16,950 | | 23 | n/a | n/a |
| Irrigation Efficiency Reward | 519 projects | $ 2,080,027 | 14,083,686 | 6,937,855 | | 18 | $ 0.027 | $ 0.179 |
| **Sector Total** | | **$ 2,080,027** | **$ 14,089,320** | **6,954,805** | | **18** | **$ 0.026** | **$ 0.179** |
| **Energy Efficiency Portfolio Total** | | **$ 25,710,414** | **$ 67,218,829** | **145,440,398** | | **11** | **$ 0.021** | **$ 0.55** |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance (codes and standards) | | | | 20,344,154 | | | | |
| Northwest Energy Efficiency Alliance (other initiatives) | | | | 4,103,978 | | | | |
| **Northwest Energy Efficiency Alliance Totals[3]** | | **$ 2,789,937** | **$ 2,789,937** | **24,448,132** | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Residential Energy Efficiency Education Initiative | | 300,175 | 300,175 | | | | | |
| **Commercial** | | | | | | | | |
| Oregon Commercial Audits | 12 audits | 7,493 | 7,493 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 2,795,885 | 2,795,885 | | | | | |
| **Total Program Direct Expense** | | **$ 41,456,433** | **$ 82,964,848** | **169,888,530** | | | | |
| Indirect Program Expenses | | 1,507,146 | 1,507,146 | | | | | |
| **Total DSM Expense** | | **$ 42,963,579** | **$ 84,471,994** | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's *2019 IRP Second Amended 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. Maximum actual demand reduction and maximum demand capacity.

[1] Peak Demand is the peak performance of each respective program and not combined performance on the actual system peak hour.

[2] Savings have been reduced by 0.44% to avoid double counting of savings in other energy efficiency programs.

[3] Savings are preliminary estimates provided by NEEA. Final savings for 2022 will be provided by NEEA April 2023.

**Appendix 4. 2022 DSM program activity by state jurisdiction**

| Program | Idaho Participants | Idaho Program Administrator Costs | Idaho Demand Reduction (MW)/ Annual Energy Savings (kWh) | Oregon Participants | Oregon Program Administrator Costs | Oregon Demand Reduction (MW)/ Annual Energy Savings (kWh) |
|---|---|---|---|---|---|---|
| **Demand Response**[1] | | | | | | |
| A/C Cool Credit | 18,910 homes | $ 805,268 | 19.9/26.5 | 217 homes | $ 24,503 | 0.2/0.3 |
| Flex Peak Program | 150 sites | 368,458 | 20.4/23.7 | 9 sites | 151,159 | 4.1/6.3 |
| Irrigation Peak Rewards | 2,708 service points | 8,230,512 | 150.0/247.2 | 64 service points | 272,628 | 5.1/8.4 |
| **Total** | | **$ 9,404,239** | **190.3/297.4** | | **$ 448,291** | **9.4/15.0** |
| **Energy Efficiency** | | | | | | |
| **Residential** | | | | | | |
| Easy Savings: Low-Income Energy Efficiency Education | 267 HVAC tune-ups | 152,718 | 22,755 | n/a HVAC tune-ups | | |
| Educational Distributions | 47,901 kits/giveaways | 1,061,944 | 3,644,643 | 1,235 kits/giveaways | 24,868 | 97,311 |
| Energy Efficient Lighting | 349,444 lightbulbs | 505,503 | 1,628,616 | 21,295 lightbulbs | 29,479 | 99,736 |
| Energy House Calls | 50 homes | 36,782 | 53,110 | 2 homes | 1,380 | 1,406 |
| Heating & Cooling Efficiency Program | 1,053 projects | 637,033 | 1,266,010 | 27 projects | 28,983 | 44,250 |
| Home Energy Audit | 425 audits | 184,858 | 28,350 | n/a audits | 0 | 0 |
| Home Energy Report Program | 104,826 treatment size | 964,791 | 20,643,379 | n/a treatment size | 0 | 0 |
| Multifamily Energy Savings Program | 97 [3] units [buildings] | 32,703 | 41,959 | 0 units [buildings] | 1,477 | 0 |
| Oregon Residential Weatherization | n/a | | | 0 audits/projects | 8,825 | 0 |
| Rebate Advantage | 91 homes | 157,855 | 239,031 | 6 homes | 9,767 | 16,510 |
| Residential New Construction Program[2] | 109 homes | 237,087 | 337,562 | n/a homes | -1,356 | 0 |
| Shade Tree Project | 1,874 trees | 128,856 | 39,595 | n/a | | |
| Weatherization Assistance for Qualified Customers | 147 homes/non-profits | 1,277,717 | 272,647 | 0 homes/non-profits | 3,778 | 0 |
| Weatherization Solutions for Eligible Customers | 27 homes | 205,788 | 48,233 | n/a homes | 0 | 0 |
| **Sector Total** | | **$ 5,583,636** | **28,265,890** | | **$ 107,203** | **259,213** |
| **Commercial** | | | | | | |
| Commercial Energy-Saving Kits | 317 kits | 21,628 | 46,237 | 17 kits | 1,142 | 2,520 |
| Custom Projects | 101 projects | 8,755,549 | 55,138,409 | 5 projects | 164,378 | 1,018,651 |
| Green Motors—Industrial | 9 motor rewinds | | 19,851 | 0 motor rewinds | | 0 |
| New Construction | 87 projects | 2,762,899 | 27,615,610 | 1 project | 17,608 | 167 |
| Retrofits | 519 projects | 4,785,965 | 22,330,625 | 6 projects | 84,950 | 560,053 |
| Small Business Direct Install | 672 projects | 1,317,868 | 3,182,196 | 8 projects | 27,561 | 46,170 |
| **Sector Total** | | **$ 17,643,909** | **108,332,928** | | **$ 295,638** | **1,627,561** |

| Program | Idaho Participants | Idaho Program Administrator Costs | Idaho Demand Reduction (MW)/ Annual Energy Savings (kWh) | Oregon Participants | Oregon Program Administrator Costs | Oregon Demand Reduction (MW)/ Annual Energy Savings (kWh) |
|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | |
| Green Motors—Irrigation | 6 motor rewinds | | 16,950 | 0 motor rewinds | | 0 |
| Irrigation Efficiency Rewards | 494 projects | 2,002,642 | 6,686,707 | 25 projects | 77,386 | 251,148 |
| **Sector Total** | | **$ 2,002,642** | **6,703,657** | | **$ 77,386** | **251,148** |
| **Market Transformation** | | | | | | |
| Northwest Energy Efficiency Alliance (codes and standards) | | | 19,326,946 | | | 1,017,208 |
| Northwest Energy Efficiency Alliance (other initiatives) | | | 3,898,779 | | | 205,199 |
| **Northwest Energy Efficiency Alliance Totals[3]** | | **$ 2,650,440** | **23,225,725** | | **$ 139,497** | **1,222,407** |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| **Residential Energy Efficiency Education Initiative** | | 289,437 | | | 10,738 | |
| **Commercial** | | | | | | |
| **Oregon Commercial Audits** | | | | 12 audits | 7,493 | |
| **Other** | | | | | | |
| **Energy Efficiency Direct Program Overhead** | | 2,655,275 | | | 140,609 | |
| **Total Program Direct Expense** | | **$ 40,229,578** | | | **$ 1,226,855** | |
| **Indirect Program Expenses** | | 1,432,203 | | | 74,942 | |
| **Total Annual Savings** | | | **166,528,201** | | | **3,360,329** |
| **Total DSM Expense** | | **$ 41,661,782** | | | **$ 1,301,797** | |

[1]. Peak Demand is the peak performance of each respective program and not combined performance on the actual system peak hour.

[2]. Oregon administrator costs are negative due to account adjustments. Amount charged to the Oregon rider was reversed and charged to the Idaho rider.

[3]. Savings are preliminary estimates provided by NEEA. Final savings for 2022 will be provided by NEEA April 2023.

# BUILDING OUR FUTURE


September 2023

# IRP

## INTEGRATED RESOURCE PLAN

APPENDIX C: **TECHNICAL REPORT**

IDAHO POWER®

## SAFE HARBOR STATEMENT

# TABLE OF CONTENTS

# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2023 Integrated Resource Plan* (IRP).

The main document, the 2023 IRP Report, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2023 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast* and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2022 Annual Report*.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

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Boise, Idaho 83702

208-388-2706

irp@idahopower.com

# IRP ADVISORY COUNCIL

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted 11 IRPAC meetings for the 2023 IRP. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Involvement from the public improves the IRP, and Idaho Power is grateful to the individuals and groups that participated in the process.

## Customer Representatives

| | |
|---|---|
| Agricultural Representative | Sid Erwin |
| Boise State University | Barry Burbank |
| Idaho Milk Products | Chris Parker |
| Idaho National Laboratory | Kurt Myers |
| KitzWorks, LLC | Kevin Kitz |
| Meta | Etta Lockey |
| Micron | Jim Swier |
| Obendorf Farms | Brock Obendorf |
| St. Luke’s Medical | Stephanie Wicks |
| Syngenta Seeds | Patrick Silveria |

## Public-Interest Representatives

| | |
|---|---|
| Boise State University Energy Policy Institute | Kathleen Araujo |
| City of Boise | Steve Burgos |
| City of Nampa | Mark Steuer |
| Clean Energy Opportunities for Idaho | Mike Heckler |
| Idaho Conservation League | Brad Heusinkveld |
| Idaho Legislature | Rep. Laurie Lickley |
| Idaho Office of Energy and Mineral Resources | Richard Stover |
| Idaho Water Resource Board | Brian Olmstead |
| National Renewable Energy Laboratory | Wesley Cole |
| Oil and Gas Industry Advisor | David Hawk |

| | |
|---|---|
| Oregon State University, Malheur Experiment Station Professor Emeritus | Clint Shock |
| Renewable Northwest | Sashwat Roy |
| Sierra Club | Lisa Young |
| Sun Valley Institute for Resilience | Herbert Romero |

## Regulatory Commission Representatives

| | |
|---|---|
| Idaho Public Utilities Commission | Matt Suess |
| Public Utility Commission of Oregon | Kim Herb |

## IRPAC Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2022 | Wednesday, May 4 | Energy Efficiency Subcommittee Meeting |
| 2022 | Tuesday, August 30 | Introductory Comments<br>Idaho Power Team Introductions<br>Advisory Council Introductions |
| 2022 | Thursday, September 8 | Review of 2021 IRP<br>2023 IRP Overview<br>Carbon Outlook<br>Transmission Update |
| 2022 | Thursday, October 13 | CSPP, Natural Gas, Energy, and Demand Forecasts |
| 2022 | Thursday, November 10 | Hydro System<br>Future Resources<br>Energy Efficiency<br>Demand Response<br>Modeling Scenarios |
| 2022 | Thursday, December 8 | Reliability and Capacity<br>Natural Gas Conversion<br>Future Supply-Side Resources<br>Modeling Scenarios |
| 2023 | Thursday, January 12 | Transmission and Distribution (T&D) Planning<br>Solar on Underutilized Lands<br>Stochastics<br>Resource Adequacy |
| 2023 | Thursday, February 9 | Modeling Update with Scenarios and Sensitivities Follow-up |
| 2023 | Thursday, March 9 | Industry Topics<br>Electrification Scenarios<br>Loss of Load Analysis |
| 2023 | Thursday, April 27 | Transmission Updates |
| 2023 | Tuesday, August 15 | Analysis Update<br>Preliminary Modeling Results |
| 2023 | Thursday, August 31 | Scenarios and Sensitivities<br>Risk Analysis<br>Preferred Portfolio and Action Plan |

# SALES AND LOAD FORECAST DATA

## Compound Annual Forecast Growth Rates

| | 2024–2029 | 2024–2034 | 2024–2043 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.14% | 1.19% | 1.06% |
| Commercial Sales | 0.71% | 0.79% | 0.83% |
| Irrigation Sales | 0.36% | 0.46% | 0.56% |
| Industrial Sales | 1.14% | 1.18% | 1.32% |
| Additional Firm Sales | 35.81% | 17.94% | 9.13% |
| System Sales | 4.22% | 2.85% | 1.87% |
| Total Sales | 4.22% | 2.85% | 1.87% |
| **Average Loads** | | | |
| Residential Load | 1.20% | 1.22% | 1.07% |
| Commercial Load | 0.78% | 0.82% | 0.84% |
| Irrigation Load | 0.42% | 0.49% | 0.58% |
| Industrial Load | 1.19% | 1.21% | 1.33% |
| Additional Firm Sales | 35.81% | 17.94% | 9.13% |
| System Load Losses | 3.37% | 2.30% | 1.59% |
| System Load | 5.40% | 3.37% | 2.12% |
| Total Load | 5.40% | 3.37% | 2.12% |
| **Peaks** | | | |
| System Peak | 3.67% | 2.49% | 1.76% |
| Total Peak | 3.67% | 2.49% | 1.76% |
| Winter Peak | 4.35% | 2.59% | 1.61% |
| Summer Peak | 3.67% | 2.49% | 1.76% |
| **Customers** | | | |
| Residential Customers | 2.01% | 1.93% | 1.60% |
| Commercial Customers | 1.53% | 1.60% | 1.50% |
| Irrigation Customers | 1.13% | 1.10% | 1.05% |
| Industrial Customers | 0.80% | 0.63% | 0.65% |

## Expected-Case Load Forecast

| 2024 Monthly Summary[1] | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 854 | 760 | 639 | 535 | 508 | 596 | 817 | 719 | 557 | 559 | 697 | 891 |
| Commercial | 535 | 493 | 467 | 449 | 459 | 499 | 557 | 537 | 495 | 478 | 493 | 534 |
| Irrigation | 4 | 4 | 14 | 156 | 372 | 626 | 696 | 578 | 344 | 70 | 9 | 4 |
| Industrial | 311 | 296 | 307 | 299 | 304 | 318 | 319 | 322 | 314 | 315 | 314 | 315 |
| Additional Firm | 137 | 138 | 137 | 132 | 127 | 129 | 128 | 127 | 119 | 131 | 152 | 163 |
| Loss | 158 | 147 | 137 | 138 | 153 | 182 | 208 | 190 | 157 | 136 | 144 | 161 |
| **System Load** | **1,998** | **1,837** | **1,701** | **1,710** | **1,923** | **2,350** | **2,725** | **2,473** | **1,986** | **1,690** | **1,809** | **2,069** |
| Light Load | 1,865 | 1,716 | 1,587 | 1,566 | 1,755 | 2,108 | 2,451 | 2,194 | 1,808 | 1,541 | 1,689 | 1,925 |
| Heavy Load | 2,103 | 1,927 | 1,791 | 1,815 | 2,055 | 2,544 | 2,941 | 2,674 | 2,141 | 1,797 | 1,905 | 2,192 |
| **Total Load** | **1,998** | **1,837** | **1,701** | **1,710** | **1,923** | **2,350** | **2,725** | **2,473** | **1,986** | **1,690** | **1,809** | **2,069** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 2,487 | 2,306 | 2,178 | 2,553 | 2,655 | 3,668 | 3,830 | 3,547 | 3,108 | 2,323 | 2,311 | 2,492 |
| **Total Peak Load** | **2,487** | **2,306** | **2,178** | **2,553** | **2,655** | **3,668** | **3,830** | **3,547** | **3,108** | **2,323** | **2,311** | **2,492** |

| 2025 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 862 | 794 | 646 | 542 | 514 | 605 | 829 | 729 | 563 | 564 | 701 | 897 |
| Commercial | 539 | 514 | 470 | 452 | 462 | 502 | 561 | 541 | 498 | 480 | 495 | 538 |
| Irrigation | 4 | 4 | 14 | 157 | 374 | 631 | 703 | 583 | 347 | 71 | 9 | 4 |
| Industrial | 317 | 312 | 313 | 304 | 310 | 324 | 325 | 328 | 319 | 321 | 320 | 319 |
| Additional Firm | 176 | 188 | 187 | 185 | 195 | 211 | 226 | 238 | 243 | 266 | 281 | 303 |
| Loss | 160 | 153 | 140 | 141 | 156 | 186 | 213 | 196 | 162 | 142 | 149 | 167 |
| **System Load** | **2,057** | **1,965** | **1,769** | **1,781** | **2,011** | **2,460** | **2,857** | **2,615** | **2,132** | **1,843** | **1,955** | **2,227** |
| Light Load | 1,920 | 1,835 | 1,650 | 1,631 | 1,835 | 2,206 | 2,570 | 2,320 | 1,941 | 1,680 | 1,825 | 2,072 |
| Heavy Load | 2,165 | 2,062 | 1,862 | 1,891 | 2,150 | 2,662 | 3,084 | 2,847 | 2,284 | 1,960 | 2,068 | 2,349 |
| **Total Load** | **2,057** | **1,965** | **1,769** | **1,781** | **2,011** | **2,460** | **2,857** | **2,615** | **2,132** | **1,843** | **1,955** | **2,227** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 2,567 | 2,391 | 2,242 | 2,635 | 2,749 | 3,788 | 4,001 | 3,729 | 3,268 | 2,494 | 2,483 | 2,656 |
| **Total Peak Load** | **2,567** | **2,391** | **2,242** | **2,635** | **2,749** | **3,788** | **4,001** | **3,729** | **3,268** | **2,494** | **2,483** | **2,656** |

1.The sales and load forecast reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2023 IRP. The peak load forecast does not include the impact of existing or new demand response programs.

| 2026 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 867 | 799 | 649 | 545 | 518 | 611 | 839 | 738 | 569 | 568 | 706 | 903 |
| Commercial | 546 | 519 | 474 | 457 | 466 | 507 | 567 | 547 | 502 | 484 | 499 | 541 |
| Irrigation | 4 | 4 | 14 | 157 | 374 | 632 | 704 | 584 | 347 | 71 | 9 | 4 |
| Industrial | 320 | 315 | 316 | 308 | 313 | 327 | 328 | 331 | 323 | 324 | 323 | 322 |
| Additional Firm | 329 | 355 | 370 | 384 | 395 | 422 | 443 | 456 | 456 | 473 | 484 | 498 |
| Loss | 166 | 160 | 146 | 148 | 163 | 194 | 221 | 204 | 170 | 149 | 156 | 174 |
| **System Load** | **2,232** | **2,152** | **1,970** | **1,998** | **2,230** | **2,693** | **3,103** | **2,860** | **2,366** | **2,069** | **2,176** | **2,442** |
| Light Load | 2,083 | 2,010 | 1,838 | 1,829 | 2,034 | 2,416 | 2,791 | 2,537 | 2,154 | 1,886 | 2,032 | 2,272 |
| Heavy Load | 2,349 | 2,259 | 2,074 | 2,121 | 2,398 | 2,896 | 3,349 | 3,115 | 2,536 | 2,201 | 2,303 | 2,576 |
| **Total Load** | **2,232** | **2,152** | **1,970** | **1,998** | **2,230** | **2,693** | **3,103** | **2,860** | **2,366** | **2,069** | **2,176** | **2,442** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 2,741 | 2,568 | 2,460 | 2,847 | 2,942 | 4,041 | 4,256 | 3,981 | 3,515 | 2,707 | 2,700 | 2,880 |
| **Total Peak Load** | **2,741** | **2,568** | **2,460** | **2,847** | **2,942** | **4,041** | **4,256** | **3,981** | **3,515** | **2,707** | **2,700** | **2,880** |

| 2027 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 874 | 805 | 655 | 550 | 524 | 619 | 852 | 749 | 577 | 574 | 713 | 913 |
| Commercial | 550 | 522 | 476 | 459 | 468 | 510 | 571 | 551 | 504 | 485 | 500 | 544 |
| Irrigation | 4 | 4 | 14 | 157 | 375 | 635 | 708 | 587 | 348 | 71 | 9 | 4 |
| Industrial | 323 | 318 | 319 | 310 | 316 | 330 | 332 | 334 | 326 | 327 | 326 | 325 |
| Additional Firm | 511 | 523 | 520 | 519 | 518 | 537 | 547 | 551 | 544 | 553 | 562 | 576 |
| Loss | 173 | 166 | 152 | 153 | 168 | 199 | 227 | 209 | 174 | 153 | 160 | 178 |
| **System Load** | **2,434** | **2,339** | **2,137** | **2,150** | **2,369** | **2,830** | **3,236** | **2,981** | **2,473** | **2,163** | **2,270** | **2,539** |
| Light Load | 2,272 | 2,184 | 1,993 | 1,968 | 2,161 | 2,538 | 2,910 | 2,645 | 2,251 | 1,972 | 2,119 | 2,362 |
| Heavy Load | 2,574 | 2,455 | 2,240 | 2,282 | 2,548 | 3,043 | 3,493 | 3,247 | 2,650 | 2,314 | 2,391 | 2,679 |
| **Total Load** | **2,434** | **2,339** | **2,137** | **2,150** | **2,369** | **2,830** | **3,236** | **2,981** | **2,473** | **2,163** | **2,270** | **2,539** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 2,949 | 2,765 | 2,633 | 3,000 | 3,061 | 4,185 | 4,406 | 4,116 | 3,625 | 2,795 | 2,792 | 2,972 |
| **Total Peak Load** | **2,949** | **2,765** | **2,633** | **3,000** | **3,061** | **4,185** | **4,406** | **4,116** | **3,625** | **2,795** | **2,792** | **2,972** |

| 2028 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 884 | 786 | 662 | 557 | 531 | 629 | 867 | 762 | 585 | 582 | 721 | 923 |
| Commercial | 555 | 509 | 480 | 463 | 472 | 514 | 577 | 556 | 508 | 488 | 503 | 547 |
| Irrigation | 4 | 4 | 14 | 157 | 375 | 636 | 710 | 589 | 349 | 71 | 9 | 4 |
| Industrial | 326 | 310 | 322 | 313 | 319 | 334 | 335 | 337 | 329 | 331 | 329 | 328 |
| Additional Firm | 578 | 584 | 587 | 583 | 577 | 592 | 598 | 598 | 585 | 589 | 594 | 604 |
| Loss | 177 | 165 | 156 | 157 | 171 | 202 | 230 | 212 | 177 | 155 | 162 | 180 |
| **System Load** | **2,523** | **2,358** | **2,220** | **2,230** | **2,445** | **2,908** | **3,317** | **3,054** | **2,533** | **2,215** | **2,317** | **2,586** |
| Light Load | 2,355 | 2,202 | 2,071 | 2,042 | 2,231 | 2,607 | 2,983 | 2,709 | 2,306 | 2,019 | 2,163 | 2,405 |
| Heavy Load | 2,668 | 2,474 | 2,328 | 2,381 | 2,615 | 3,127 | 3,604 | 3,304 | 2,715 | 2,370 | 2,441 | 2,741 |
| **Total Load** | **2,523** | **2,358** | **2,220** | **2,230** | **2,445** | **2,908** | **3,317** | **3,054** | **2,533** | **2,215** | **2,317** | **2,586** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,038 | 2,853 | 2,714 | 3,074 | 3,121 | 4,269 | 4,501 | 4,204 | 3,695 | 2,845 | 2,840 | 3,011 |
| **Total Peak Load** | **3,038** | **2,853** | **2,714** | **3,074** | **3,121** | **4,269** | **4,501** | **4,204** | **3,695** | **2,845** | **2,840** | **3,011** |

| 2029 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 894 | 824 | 670 | 564 | 539 | 640 | 883 | 776 | 595 | 589 | 729 | 934 |
| Commercial | 560 | 531 | 483 | 467 | 474 | 517 | 582 | 560 | 511 | 491 | 505 | 552 |
| Irrigation | 4 | 4 | 14 | 157 | 375 | 638 | 712 | 591 | 350 | 71 | 9 | 4 |
| Industrial | 329 | 324 | 325 | 317 | 322 | 337 | 338 | 341 | 332 | 334 | 332 | 331 |
| Additional Firm | 605 | 615 | 615 | 613 | 609 | 628 | 637 | 638 | 627 | 631 | 637 | 648 |
| Loss | 179 | 172 | 158 | 159 | 174 | 205 | 233 | 215 | 180 | 157 | 164 | 183 |
| **System Load** | **2,570** | **2,470** | **2,265** | **2,276** | **2,493** | **2,965** | **3,386** | **3,122** | **2,595** | **2,273** | **2,377** | **2,652** |
| Light Load | 2,399 | 2,306 | 2,112 | 2,083 | 2,274 | 2,659 | 3,045 | 2,770 | 2,362 | 2,072 | 2,219 | 2,467 |
| Heavy Load | 2,706 | 2,592 | 2,374 | 2,429 | 2,666 | 3,189 | 3,679 | 3,377 | 2,798 | 2,418 | 2,503 | 2,811 |
| **Total Load** | **2,570** | **2,470** | **2,265** | **2,276** | **2,493** | **2,965** | **3,386** | **3,122** | **2,595** | **2,273** | **2,377** | **2,652** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,085 | 2,899 | 2,755 | 3,114 | 3,161 | 4,337 | 4,585 | 4,288 | 3,767 | 2,900 | 2,898 | 3,070 |
| **Total Peak Load** | **3,085** | **2,899** | **2,755** | **3,114** | **3,161** | **4,337** | **4,585** | **4,288** | **3,767** | **2,900** | **2,898** | **3,070** |

| 2030 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 904 | 833 | 678 | 571 | 546 | 651 | 899 | 789 | 604 | 596 | 736 | 943 |
| Commercial | 568 | 537 | 488 | 472 | 479 | 523 | 589 | 568 | 516 | 495 | 510 | 555 |
| Irrigation | 4 | 4 | 14 | 157 | 377 | 641 | 716 | 594 | 352 | 71 | 9 | 4 |
| Industrial | 333 | 328 | 329 | 320 | 326 | 341 | 342 | 344 | 336 | 338 | 336 | 335 |
| Additional Firm | 667 | 677 | 668 | 661 | 654 | 674 | 682 | 683 | 671 | 677 | 684 | 697 |
| Loss | 182 | 175 | 160 | 161 | 176 | 208 | 237 | 219 | 182 | 160 | 167 | 186 |
| **System Load** | **2,658** | **2,554** | **2,337** | **2,343** | **2,559** | **3,038** | **3,465** | **3,197** | **2,660** | **2,337** | **2,442** | **2,720** |
| Light Load | 2,480 | 2,385 | 2,180 | 2,145 | 2,334 | 2,724 | 3,116 | 2,836 | 2,422 | 2,130 | 2,280 | 2,530 |
| Heavy Load | 2,798 | 2,681 | 2,461 | 2,488 | 2,736 | 3,289 | 3,740 | 3,458 | 2,869 | 2,486 | 2,572 | 2,883 |
| **Total Load** | **2,658** | **2,554** | **2,337** | **2,343** | **2,559** | **3,038** | **3,465** | **3,197** | **2,660** | **2,337** | **2,442** | **2,720** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,176 | 2,983 | 2,830 | 3,178 | 3,220 | 4,420 | 4,679 | 4,381 | 3,848 | 2,970 | 2,968 | 3,133 |
| **Total Peak Load** | **3,176** | **2,983** | **2,830** | **3,178** | **3,220** | **4,420** | **4,679** | **4,381** | **3,848** | **2,970** | **2,968** | **3,133** |

| 2031 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 914 | 842 | 686 | 578 | 554 | 662 | 915 | 804 | 614 | 604 | 745 | 954 |
| Commercial | 572 | 541 | 491 | 475 | 482 | 526 | 594 | 572 | 519 | 497 | 512 | 559 |
| Irrigation | 4 | 4 | 14 | 158 | 378 | 644 | 720 | 598 | 353 | 72 | 9 | 4 |
| Industrial | 337 | 332 | 333 | 324 | 330 | 345 | 346 | 348 | 340 | 342 | 340 | 339 |
| Additional Firm | 696 | 705 | 696 | 688 | 680 | 698 | 704 | 702 | 688 | 692 | 697 | 707 |
| Loss | 185 | 177 | 162 | 163 | 178 | 210 | 240 | 221 | 184 | 161 | 168 | 187 |
| **System Load** | **2,707** | **2,601** | **2,381** | **2,386** | **2,602** | **3,085** | **3,519** | **3,246** | **2,698** | **2,368** | **2,471** | **2,752** |
| Light Load | 2,526 | 2,429 | 2,221 | 2,184 | 2,374 | 2,766 | 3,164 | 2,879 | 2,456 | 2,158 | 2,307 | 2,560 |
| Heavy Load | 2,838 | 2,730 | 2,507 | 2,534 | 2,767 | 3,340 | 3,775 | 3,535 | 2,875 | 2,519 | 2,603 | 2,891 |
| **Total Load** | **2,707** | **2,601** | **2,381** | **2,386** | **2,602** | **3,085** | **3,519** | **3,246** | **2,698** | **2,368** | **2,471** | **2,752** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,224 | 3,032 | 2,870 | 3,215 | 3,258 | 4,478 | 4,747 | 4,446 | 3,902 | 3,003 | 2,997 | 3,156 |
| **Total Peak Load** | **3,224** | **3,032** | **2,870** | **3,215** | **3,258** | **4,478** | **4,747** | **4,446** | **3,902** | **3,003** | **2,997** | **3,156** |

| 2032 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Average Load (aMW) 70th Percentile | | | | | | | |
| Residential | 924 | 823 | 694 | 585 | 562 | 672 | 931 | 817 | 622 | 611 | 752 | 962 |
| Commercial | 579 | 528 | 495 | 480 | 487 | 531 | 601 | 578 | 523 | 502 | 516 | 563 |
| Irrigation | 4 | 4 | 14 | 158 | 380 | 648 | 724 | 601 | 355 | 72 | 9 | 4 |
| Industrial | 341 | 324 | 336 | 328 | 333 | 349 | 350 | 352 | 344 | 346 | 344 | 344 |
| Additional Firm | 705 | 706 | 701 | 692 | 683 | 701 | 706 | 705 | 690 | 694 | 699 | 709 |
| Loss | 187 | 174 | 164 | 165 | 180 | 212 | 242 | 223 | 186 | 162 | 169 | 188 |
| **System Load** | **2,739** | **2,558** | **2,404** | **2,408** | **2,624** | **3,113** | **3,554** | **3,277** | **2,721** | **2,386** | **2,488** | **2,771** |
| Light Load | 2,556 | 2,388 | 2,242 | 2,204 | 2,394 | 2,791 | 3,196 | 2,907 | 2,476 | 2,174 | 2,323 | 2,578 |
| Heavy Load | 2,871 | 2,696 | 2,521 | 2,557 | 2,806 | 3,348 | 3,813 | 3,569 | 2,899 | 2,552 | 2,609 | 2,911 |
| **Total Load** | **2,739** | **2,558** | **2,404** | **2,408** | **2,624** | **3,113** | **3,554** | **3,277** | **2,721** | **2,386** | **2,488** | **2,771** |
| | | | | | Peak Load (MW) 70th Percentile | | | | | | | |
| System Peak Load (1 hour) | 3,255 | 3,058 | 2,888 | 3,230 | 3,283 | 4,520 | 4,797 | 4,495 | 3,943 | 3,025 | 3,015 | 3,169 |
| **Total Peak Load** | **3,255** | **3,058** | **2,888** | **3,230** | **3,283** | **4,520** | **4,797** | **4,495** | **3,943** | **3,025** | **3,015** | **3,169** |

| 2033 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Average Load (aMW) 70th Percentile | | | | | | | |
| Residential | 933 | 860 | 700 | 592 | 569 | 682 | 946 | 831 | 631 | 618 | 759 | 972 |
| Commercial | 584 | 551 | 499 | 484 | 490 | 535 | 606 | 583 | 527 | 504 | 518 | 567 |
| Irrigation | 4 | 4 | 14 | 159 | 382 | 652 | 729 | 605 | 357 | 72 | 9 | 4 |
| Industrial | 345 | 340 | 341 | 332 | 338 | 353 | 354 | 357 | 348 | 350 | 348 | 348 |
| Additional Firm | 707 | 714 | 703 | 694 | 685 | 703 | 709 | 707 | 693 | 696 | 701 | 712 |
| Loss | 188 | 180 | 165 | 166 | 181 | 214 | 244 | 225 | 187 | 164 | 170 | 190 |
| **System Load** | **2,761** | **2,648** | **2,422** | **2,426** | **2,644** | **3,139** | **3,588** | **3,308** | **2,743** | **2,403** | **2,506** | **2,793** |
| Light Load | 2,576 | 2,473 | 2,258 | 2,221 | 2,412 | 2,815 | 3,227 | 2,934 | 2,497 | 2,191 | 2,339 | 2,598 |
| Heavy Load | 2,906 | 2,780 | 2,539 | 2,576 | 2,828 | 3,376 | 3,874 | 3,579 | 2,923 | 2,571 | 2,628 | 2,934 |
| **Total Load** | **2,761** | **2,648** | **2,422** | **2,426** | **2,644** | **3,139** | **3,588** | **3,308** | **2,743** | **2,403** | **2,506** | **2,793** |
| | | | | | Peak Load (MW) 70th Percentile | | | | | | | |
| System Peak Load (1 hour) | 3,276 | 3,079 | 2,902 | 3,243 | 3,305 | 4,560 | 4,847 | 4,545 | 3,984 | 3,047 | 3,033 | 3,183 |
| **Total Peak Load** | **3,276** | **3,079** | **2,902** | **3,243** | **3,305** | **4,560** | **4,847** | **4,545** | **3,984** | **3,047** | **3,033** | **3,183** |

| 2034 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 942 | 868 | 707 | 597 | 575 | 692 | 960 | 842 | 638 | 622 | 763 | 977 |
| Commercial | 591 | 556 | 503 | 489 | 494 | 540 | 613 | 590 | 531 | 508 | 522 | 572 |
| Irrigation | 4 | 4 | 14 | 160 | 384 | 656 | 734 | 609 | 360 | 73 | 9 | 5 |
| Industrial | 350 | 345 | 345 | 336 | 342 | 358 | 359 | 362 | 353 | 355 | 353 | 353 |
| Additional Firm | 710 | 717 | 706 | 697 | 687 | 706 | 711 | 710 | 695 | 699 | 704 | 714 |
| Loss | 189 | 181 | 166 | 167 | 182 | 215 | 247 | 227 | 188 | 164 | 171 | 191 |
| **System Load** | **2,785** | **2,671** | **2,441** | **2,446** | **2,666** | **3,167** | **3,623** | **3,340** | **2,766** | **2,420** | **2,522** | **2,812** |
| Light Load | 2,599 | 2,494 | 2,277 | 2,239 | 2,431 | 2,839 | 3,258 | 2,962 | 2,517 | 2,206 | 2,354 | 2,615 |
| Heavy Load | 2,932 | 2,803 | 2,560 | 2,612 | 2,835 | 3,406 | 3,911 | 3,612 | 2,947 | 2,589 | 2,644 | 2,966 |
| **Total Load** | **2,785** | **2,671** | **2,441** | **2,446** | **2,666** | **3,167** | **3,623** | **3,340** | **2,766** | **2,420** | **2,522** | **2,812** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,299 | 3,097 | 2,917 | 3,256 | 3,330 | 4,601 | 4,897 | 4,594 | 4,025 | 3,068 | 3,049 | 3,195 |
| **Total Peak Load** | **3,299** | **3,097** | **2,917** | **3,256** | **3,330** | **4,601** | **4,897** | **4,594** | **4,025** | **3,068** | **3,049** | **3,195** |

| 2035 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 947 | 873 | 711 | 602 | 581 | 700 | 973 | 853 | 645 | 627 | 768 | 983 |
| Commercial | 598 | 562 | 508 | 494 | 499 | 546 | 620 | 597 | 536 | 512 | 526 | 576 |
| Irrigation | 4 | 4 | 14 | 161 | 387 | 660 | 739 | 614 | 362 | 73 | 9 | 5 |
| Industrial | 355 | 350 | 350 | 341 | 347 | 363 | 364 | 367 | 358 | 360 | 358 | 358 |
| Additional Firm | 710 | 717 | 706 | 697 | 688 | 706 | 711 | 710 | 695 | 699 | 704 | 715 |
| Loss | 190 | 182 | 167 | 168 | 183 | 217 | 249 | 229 | 190 | 165 | 172 | 192 |
| **System Load** | **2,804** | **2,688** | **2,456** | **2,463** | **2,684** | **3,191** | **3,656** | **3,369** | **2,786** | **2,436** | **2,537** | **2,828** |
| Light Load | 2,616 | 2,509 | 2,291 | 2,254 | 2,448 | 2,862 | 3,287 | 2,988 | 2,536 | 2,221 | 2,368 | 2,630 |
| Heavy Load | 2,939 | 2,821 | 2,575 | 2,629 | 2,855 | 3,432 | 3,947 | 3,645 | 2,987 | 2,592 | 2,660 | 2,983 |
| **Total Load** | **2,804** | **2,688** | **2,456** | **2,463** | **2,684** | **3,191** | **3,656** | **3,369** | **2,786** | **2,436** | **2,537** | **2,828** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,316 | 3,113 | 2,928 | 3,267 | 3,351 | 4,640 | 4,944 | 4,642 | 4,065 | 3,088 | 3,064 | 3,204 |
| **Total Peak Load** | **3,316** | **3,113** | **2,928** | **3,267** | **3,351** | **4,640** | **4,944** | **4,642** | **4,065** | **3,088** | **3,064** | **3,204** |

| 2036 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 954 | 849 | 717 | 607 | 587 | 709 | 987 | 866 | 654 | 633 | 774 | 990 |
| Commercial | 604 | 547 | 511 | 498 | 502 | 549 | 626 | 602 | 539 | 515 | 528 | 580 |
| Irrigation | 4 | 4 | 14 | 162 | 389 | 665 | 744 | 618 | 365 | 74 | 9 | 5 |
| Industrial | 360 | 342 | 355 | 346 | 352 | 368 | 369 | 372 | 363 | 365 | 363 | 363 |
| Additional Firm | 711 | 712 | 707 | 698 | 688 | 706 | 712 | 710 | 696 | 700 | 705 | 716 |
| Loss | 192 | 179 | 168 | 169 | 184 | 219 | 251 | 231 | 191 | 166 | 173 | 193 |
| **System Load** | **2,823** | **2,632** | **2,472** | **2,479** | **2,703** | **3,217** | **3,689** | **3,399** | **2,807** | **2,452** | **2,552** | **2,846** |
| Light Load | 2,634 | 2,458 | 2,305 | 2,269 | 2,465 | 2,884 | 3,317 | 3,015 | 2,555 | 2,235 | 2,382 | 2,648 |
| Heavy Load | 2,959 | 2,761 | 2,603 | 2,632 | 2,874 | 3,483 | 3,958 | 3,702 | 2,992 | 2,609 | 2,688 | 2,990 |
| **Total Load** | **2,823** | **2,632** | **2,472** | **2,479** | **2,703** | **3,217** | **3,689** | **3,399** | **2,807** | **2,452** | **2,552** | **2,846** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,333 | 3,131 | 2,940 | 3,278 | 3,373 | 4,679 | 4,992 | 4,690 | 4,105 | 3,109 | 3,080 | 3,215 |
| **Total Peak Load** | **3,333** | **3,131** | **2,940** | **3,278** | **3,373** | **4,679** | **4,992** | **4,690** | **4,105** | **3,109** | **3,080** | **3,215** |

| 2037 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 961 | 886 | 723 | 613 | 594 | 719 | 1,003 | 879 | 662 | 639 | 780 | 998 |
| Commercial | 610 | 572 | 515 | 502 | 506 | 554 | 632 | 607 | 543 | 518 | 531 | 584 |
| Irrigation | 4 | 4 | 15 | 163 | 391 | 670 | 750 | 623 | 367 | 74 | 9 | 5 |
| Industrial | 365 | 359 | 360 | 351 | 357 | 373 | 374 | 377 | 368 | 370 | 368 | 369 |
| Additional Firm | 710 | 718 | 706 | 697 | 688 | 706 | 712 | 710 | 696 | 699 | 705 | 715 |
| Loss | 193 | 184 | 169 | 170 | 186 | 220 | 253 | 233 | 192 | 167 | 174 | 194 |
| **System Load** | **2,843** | **2,723** | **2,488** | **2,496** | **2,722** | **3,242** | **3,723** | **3,430** | **2,829** | **2,468** | **2,567** | **2,865** |
| Light Load | 2,653 | 2,543 | 2,320 | 2,285 | 2,482 | 2,907 | 3,348 | 3,042 | 2,575 | 2,250 | 2,396 | 2,665 |
| Heavy Load | 2,980 | 2,859 | 2,620 | 2,650 | 2,911 | 3,487 | 3,995 | 3,736 | 3,014 | 2,626 | 2,704 | 3,009 |
| **Total Load** | **2,843** | **2,723** | **2,488** | **2,496** | **2,722** | **3,242** | **3,723** | **3,430** | **2,829** | **2,468** | **2,567** | **2,865** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,352 | 3,149 | 2,951 | 3,288 | 3,396 | 4,719 | 5,041 | 4,739 | 4,147 | 3,129 | 3,096 | 3,226 |
| **Total Peak Load** | **3,352** | **3,149** | **2,951** | **3,288** | **3,396** | **4,719** | **5,041** | **4,739** | **4,147** | **3,129** | **3,096** | **3,226** |

| 2038 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 968 | 893 | 729 | 619 | 601 | 729 | 1,017 | 892 | 670 | 645 | 785 | 1,004 |
| Commercial | 617 | 577 | 520 | 507 | 510 | 559 | 639 | 614 | 548 | 522 | 535 | 589 |
| Irrigation | 4 | 4 | 15 | 163 | 394 | 674 | 755 | 627 | 370 | 74 | 9 | 5 |
| Industrial | 370 | 365 | 366 | 356 | 362 | 379 | 380 | 383 | 373 | 375 | 374 | 374 |
| Additional Firm | 710 | 718 | 706 | 697 | 688 | 706 | 711 | 710 | 696 | 699 | 704 | 715 |
| Loss | 194 | 186 | 170 | 171 | 187 | 222 | 255 | 235 | 194 | 168 | 175 | 195 |
| **System Load** | **2,864** | **2,742** | **2,505** | **2,514** | **2,742** | **3,269** | **3,759** | **3,461** | **2,851** | **2,485** | **2,582** | **2,883** |
| Light Load | 2,672 | 2,561 | 2,336 | 2,301 | 2,501 | 2,931 | 3,380 | 3,070 | 2,595 | 2,265 | 2,411 | 2,682 |
| Heavy Load | 3,015 | 2,879 | 2,626 | 2,669 | 2,932 | 3,516 | 4,032 | 3,770 | 3,038 | 2,658 | 2,708 | 3,028 |
| **Total Load** | **2,864** | **2,742** | **2,505** | **2,514** | **2,742** | **3,269** | **3,759** | **3,461** | **2,851** | **2,485** | **2,582** | **2,883** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,372 | 3,168 | 2,964 | 3,299 | 3,420 | 4,760 | 5,091 | 4,789 | 4,190 | 3,151 | 3,112 | 3,237 |
| **Total Peak Load** | **3,372** | **3,168** | **2,964** | **3,299** | **3,420** | **4,760** | **5,091** | **4,789** | **4,190** | **3,151** | **3,112** | **3,237** |

| 2039 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 975 | 899 | 734 | 624 | 607 | 738 | 1,031 | 904 | 678 | 650 | 789 | 1,009 |
| Commercial | 625 | 584 | 525 | 513 | 515 | 565 | 647 | 621 | 553 | 527 | 539 | 594 |
| Irrigation | 4 | 4 | 15 | 164 | 396 | 679 | 761 | 632 | 372 | 75 | 9 | 5 |
| Industrial | 376 | 370 | 371 | 361 | 368 | 385 | 386 | 389 | 379 | 381 | 379 | 380 |
| Additional Firm | 710 | 717 | 706 | 697 | 688 | 706 | 711 | 710 | 696 | 699 | 704 | 715 |
| Loss | 195 | 187 | 171 | 172 | 188 | 224 | 258 | 237 | 195 | 169 | 176 | 196 |
| **System Load** | **2,885** | **2,761** | **2,522** | **2,532** | **2,762** | **3,296** | **3,794** | **3,493** | **2,873** | **2,501** | **2,597** | **2,899** |
| Light Load | 2,692 | 2,578 | 2,352 | 2,317 | 2,519 | 2,955 | 3,411 | 3,098 | 2,615 | 2,280 | 2,425 | 2,697 |
| Heavy Load | 3,037 | 2,899 | 2,644 | 2,688 | 2,954 | 3,545 | 4,095 | 3,778 | 3,062 | 2,676 | 2,724 | 3,045 |
| **Total Load** | **2,885** | **2,761** | **2,522** | **2,532** | **2,762** | **3,296** | **3,794** | **3,493** | **2,873** | **2,501** | **2,597** | **2,899** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,392 | 3,186 | 2,976 | 3,311 | 3,444 | 4,800 | 5,140 | 4,839 | 4,233 | 3,172 | 3,127 | 3,246 |
| **Total Peak Load** | **3,392** | **3,186** | **2,976** | **3,311** | **3,444** | **4,800** | **5,140** | **4,839** | **4,233** | **3,172** | **3,127** | **3,246** |

| 2040 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 980 | 873 | 739 | 629 | 613 | 747 | 1,045 | 916 | 685 | 655 | 794 | 1,015 |
| Commercial | 631 | 569 | 529 | 518 | 520 | 570 | 654 | 628 | 557 | 531 | 543 | 598 |
| Irrigation | 4 | 4 | 15 | 165 | 398 | 684 | 766 | 636 | 375 | 75 | 10 | 5 |
| Industrial | 382 | 363 | 377 | 367 | 373 | 391 | 392 | 395 | 385 | 387 | 385 | 386 |
| Additional Firm | 709 | 710 | 706 | 697 | 687 | 705 | 711 | 709 | 695 | 699 | 704 | 714 |
| Loss | 197 | 183 | 172 | 173 | 189 | 225 | 260 | 239 | 196 | 170 | 177 | 197 |
| **System Load** | **2,903** | **2,702** | **2,537** | **2,548** | **2,781** | **3,322** | **3,827** | **3,523** | **2,894** | **2,517** | **2,611** | **2,915** |
| Light Load | 2,709 | 2,523 | 2,366 | 2,332 | 2,536 | 2,978 | 3,441 | 3,124 | 2,634 | 2,294 | 2,438 | 2,711 |
| Heavy Load | 3,056 | 2,835 | 2,660 | 2,721 | 2,958 | 3,573 | 4,132 | 3,811 | 3,102 | 2,678 | 2,739 | 3,075 |
| **Total Load** | **2,903** | **2,702** | **2,537** | **2,548** | **2,781** | **3,322** | **3,827** | **3,523** | **2,894** | **2,517** | **2,611** | **2,915** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,409 | 3,203 | 2,987 | 3,321 | 3,467 | 4,840 | 5,188 | 4,888 | 4,274 | 3,192 | 3,142 | 3,256 |
| **Total Peak Load** | **3,409** | **3,203** | **2,987** | **3,321** | **3,467** | **4,840** | **5,188** | **4,888** | **4,274** | **3,192** | **3,142** | **3,256** |

| 2041 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 985 | 909 | 743 | 633 | 619 | 756 | 1,058 | 927 | 692 | 660 | 798 | 1,020 |
| Commercial | 638 | 595 | 534 | 523 | 524 | 575 | 661 | 634 | 562 | 535 | 546 | 602 |
| Irrigation | 4 | 4 | 15 | 166 | 401 | 688 | 772 | 641 | 377 | 76 | 10 | 5 |
| Industrial | 387 | 382 | 382 | 372 | 379 | 396 | 398 | 401 | 391 | 393 | 391 | 391 |
| Additional Firm | 719 | 726 | 714 | 704 | 693 | 711 | 716 | 715 | 701 | 706 | 712 | 723 |
| Loss | 198 | 189 | 173 | 174 | 191 | 227 | 262 | 241 | 198 | 172 | 178 | 198 |
| **System Load** | **2,932** | **2,805** | **2,561** | **2,572** | **2,806** | **3,354** | **3,867** | **3,559** | **2,921** | **2,541** | **2,634** | **2,940** |
| Light Load | 2,736 | 2,619 | 2,388 | 2,355 | 2,559 | 3,007 | 3,477 | 3,156 | 2,659 | 2,316 | 2,459 | 2,735 |
| Heavy Load | 3,073 | 2,945 | 2,696 | 2,732 | 2,985 | 3,631 | 4,149 | 3,850 | 3,131 | 2,703 | 2,763 | 3,102 |
| **Total Load** | **2,932** | **2,805** | **2,561** | **2,572** | **2,806** | **3,354** | **3,867** | **3,559** | **2,921** | **2,541** | **2,634** | **2,940** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,427 | 3,221 | 3,005 | 3,340 | 3,496 | 4,886 | 5,242 | 4,943 | 4,322 | 3,223 | 3,167 | 3,265 |
| **Total Peak Load** | **3,427** | **3,221** | **3,005** | **3,340** | **3,496** | **4,886** | **5,242** | **4,943** | **4,322** | **3,223** | **3,167** | **3,265** |

| 2042 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 990 | 914 | 748 | 638 | 624 | 765 | 1,072 | 939 | 700 | 664 | 802 | 1,024 |
| Commercial | 644 | 600 | 537 | 527 | 527 | 579 | 667 | 640 | 566 | 538 | 549 | 606 |
| Irrigation | 4 | 4 | 15 | 167 | 403 | 693 | 777 | 646 | 380 | 76 | 10 | 5 |
| Industrial | 393 | 387 | 388 | 378 | 385 | 402 | 404 | 407 | 396 | 399 | 397 | 397 |
| Additional Firm | 719 | 726 | 714 | 704 | 693 | 711 | 716 | 715 | 701 | 706 | 712 | 723 |
| Loss | 199 | 190 | 174 | 175 | 192 | 229 | 264 | 243 | 199 | 172 | 179 | 199 |
| **System Load** | **2,950** | **2,822** | **2,575** | **2,588** | **2,825** | **3,379** | **3,900** | **3,589** | **2,942** | **2,556** | **2,648** | **2,955** |
| Light Load | 2,752 | 2,634 | 2,402 | 2,369 | 2,576 | 3,029 | 3,506 | 3,183 | 2,678 | 2,329 | 2,472 | 2,749 |
| Heavy Load | 3,092 | 2,962 | 2,712 | 2,749 | 3,004 | 3,658 | 4,184 | 3,909 | 3,135 | 2,719 | 2,789 | 3,104 |
| **Total Load** | **2,950** | **2,822** | **2,575** | **2,588** | **2,825** | **3,379** | **3,900** | **3,589** | **2,942** | **2,556** | **2,648** | **2,955** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,444 | 3,237 | 3,016 | 3,351 | 3,518 | 4,925 | 5,290 | 4,991 | 4,362 | 3,242 | 3,181 | 3,274 |
| **Total Peak Load** | **3,444** | **3,237** | **3,016** | **3,351** | **3,518** | **4,925** | **5,290** | **4,991** | **4,362** | **3,242** | **3,181** | **3,274** |

| 2043 Monthly Summary | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | | | |
| Residential | 995 | 919 | 752 | 642 | 630 | 773 | 1,084 | 950 | 706 | 669 | 805 | 1,028 |
| Commercial | 650 | 605 | 541 | 531 | 531 | 583 | 673 | 646 | 569 | 541 | 552 | 610 |
| Irrigation | 4 | 4 | 15 | 168 | 405 | 697 | 783 | 650 | 382 | 77 | 10 | 5 |
| Industrial | 399 | 393 | 394 | 383 | 390 | 408 | 409 | 413 | 402 | 404 | 403 | 403 |
| Additional Firm | 719 | 726 | 714 | 704 | 693 | 711 | 716 | 715 | 701 | 706 | 712 | 723 |
| Loss | 200 | 191 | 175 | 176 | 193 | 230 | 266 | 245 | 200 | 173 | 179 | 200 |
| **System Load** | **2,968** | **2,838** | **2,590** | **2,605** | **2,843** | **3,403** | **3,932** | **3,617** | **2,962** | **2,570** | **2,661** | **2,970** |
| Light Load | 2,769 | 2,650 | 2,415 | 2,384 | 2,593 | 3,052 | 3,535 | 3,208 | 2,696 | 2,342 | 2,484 | 2,762 |
| Heavy Load | 3,111 | 2,979 | 2,727 | 2,766 | 3,040 | 3,661 | 4,218 | 3,940 | 3,156 | 2,734 | 2,803 | 3,119 |
| **Total Load** | **2,968** | **2,838** | **2,590** | **2,605** | **2,843** | **3,403** | **3,932** | **3,617** | **2,962** | **2,570** | **2,661** | **2,970** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | | | |
| System Peak Load (1 hour) | 3,461 | 3,252 | 3,026 | 3,361 | 3,539 | 4,964 | 5,337 | 5,038 | 4,401 | 3,261 | 3,194 | 3,283 |
| **Total Peak Load** | **3,461** | **3,252** | **3,026** | **3,361** | **3,539** | **4,964** | **5,337** | **5,038** | **4,401** | **3,261** | **3,194** | **3,283** |

## Annual Summary

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh) 70th Percentile** | | | | | | | | | | |
| Residential | 5,952,203 | 6,015,372 | 6,064,292 | 6,131,412 | 6,212,505 | 6,299,614 | 6,383,861 | 6,471,568 | 6,555,018 | 6,633,732 |
| Commercial | 4,389,449 | 4,415,395 | 4,459,613 | 4,481,988 | 4,518,268 | 4,548,417 | 4,599,132 | 4,627,083 | 4,672,632 | 4,704,762 |
| Irrigation | 2,112,332 | 2,130,433 | 2,131,886 | 2,140,898 | 2,145,544 | 2,151,055 | 2,161,512 | 2,172,343 | 2,184,166 | 2,197,504 |
| Industrial | 2,730,923 | 2,780,341 | 2,808,143 | 2,835,162 | 2,861,510 | 2,890,833 | 2,922,399 | 2,956,967 | 2,991,128 | 3,029,583 |
| Additional Firm | 1,185,562 | 1,972,275 | 3,702,016 | 4,717,323 | 5,174,670 | 5,477,596 | 5,909,535 | 6,097,135 | 6,140,903 | 6,149,345 |
| **System Load** | **16,370,468** | **17,313,815** | **19,165,950** | **20,306,782** | **20,912,497** | **21,367,515** | **21,976,439** | **22,325,096** | **22,543,847** | **22,714,925** |
| **Total Load** | **16,370,468** | **17,313,815** | **19,165,950** | **20,306,782** | **20,912,497** | **21,367,515** | **21,976,439** | **22,325,096** | **22,543,847** | **22,714,925** |
| **Generation Month Sales (MWh) 70th Percentile** | | | | | | | | | | |
| Residential | 5,956,695 | 6,018,895 | 6,068,360 | 6,136,888 | 6,218,381 | 6,305,689 | 6,389,286 | 6,477,861 | 6,559,842 | 6,639,006 |
| Commercial | 4,390,873 | 4,417,970 | 4,460,805 | 4,484,056 | 4,519,947 | 4,551,390 | 4,600,667 | 4,629,723 | 4,674,424 | 4,707,375 |
| Irrigation | 2,112,350 | 2,130,436 | 2,131,896 | 2,140,904 | 2,145,550 | 2,151,065 | 2,161,523 | 2,172,355 | 2,184,179 | 2,197,517 |
| Industrial | 2,735,093 | 2,782,687 | 2,810,423 | 2,837,385 | 2,863,985 | 2,893,497 | 2,925,317 | 2,959,850 | 2,994,373 | 3,033,114 |
| Additional Firm | 1,185,562 | 1,972,275 | 3,702,016 | 4,717,323 | 5,174,670 | 5,477,596 | 5,909,535 | 6,097,135 | 6,140,903 | 6,149,345 |
| **System Sales** | **16,380,573** | **17,322,263** | **19,173,500** | **20,316,557** | **20,922,533** | **21,379,236** | **21,986,327** | **22,336,924** | **22,553,721** | **22,726,358** |
| **Total Sales** | **16,380,573** | **17,322,263** | **19,173,500** | **20,316,557** | **20,922,533** | **21,379,236** | **21,986,327** | **22,336,924** | **22,553,721** | **22,726,358** |
| Loss | 1,400,102 | 1,435,438 | 1,499,307 | 1,542,889 | 1,570,420 | 1,591,049 | 1,617,688 | 1,635,569 | 1,649,836 | 1,660,426 |
| **Required Supply** | **17,780,674** | **18,757,701** | **20,672,807** | **21,859,447** | **22,492,953** | **22,970,286** | **23,604,015** | **23,972,493** | **24,203,558** | **24,386,784** |
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | |
| Residential | 678 | 687 | 693 | 701 | 708 | 720 | 729 | 739 | 747 | 758 |
| Commercial | 500 | 504 | 509 | 512 | 515 | 520 | 525 | 529 | 532 | 537 |
| Irrigation | 240 | 243 | 243 | 244 | 244 | 246 | 247 | 248 | 249 | 251 |
| Industrial | 311 | 318 | 321 | 324 | 326 | 330 | 334 | 338 | 341 | 346 |
| Additional Firm | 135 | 225 | 423 | 539 | 589 | 625 | 675 | 696 | 699 | 702 |
| Loss | 159 | 164 | 171 | 176 | 179 | 182 | 185 | 187 | 188 | 190 |
| **System Load** | **2,024** | **2,141** | **2,360** | **2,495** | **2,561** | **2,622** | **2,695** | **2,737** | **2,755** | **2,784** |
| Light Load | 1,852 | 1,959 | 2,159 | 2,283 | 2,343 | 2,399 | 2,465 | 2,503 | 2,521 | 2,547 |
| Heavy Load | 2,159 | 2,285 | 2,518 | 2,662 | 2,733 | 2,798 | 2,874 | 2,912 | 2,931 | 2,962 |
| **Total Load** | **2,024** | **2,141** | **2,360** | **2,495** | **2,561** | **2,622** | **2,695** | **2,737** | **2,755** | **2,784** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | |
| System Peak (1 hour) | 3,830 | 4,001 | 4,256 | 4,406 | 4,501 | 4,585 | 4,679 | 4,747 | 4,797 | 4,847 |
| **Total Peak Load** | **3,830** | **4,001** | **4,256** | **4,406** | **4,501** | **4,585** | **4,679** | **4,747** | **4,797** | **4,847** |

| | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh) 70th Percentile** | | | | | | | | | | |
| Residential | 6,701,009 | 6,759,420 | 6,828,122 | 6,902,280 | 6,972,664 | 7,035,828 | 7,095,241 | 7,154,048 | 7,212,029 | 7,266,306 |
| Commercial | 4,750,003 | 4,798,757 | 4,831,415 | 4,871,061 | 4,917,076 | 4,968,676 | 5,011,749 | 5,056,679 | 5,094,573 | 5,132,734 |
| Irrigation | 2,211,654 | 2,226,398 | 2,241,679 | 2,257,279 | 2,272,690 | 2,288,397 | 2,304,043 | 2,319,739 | 2,335,293 | 2,350,298 |
| Industrial | 3,071,424 | 3,114,153 | 3,157,745 | 3,201,940 | 3,250,317 | 3,300,396 | 3,350,607 | 3,400,422 | 3,450,450 | 3,501,215 |
| Additional Firm | 6,171,167 | 6,172,006 | 6,193,102 | 6,177,196 | 6,176,327 | 6,173,887 | 6,183,582 | 6,234,425 | 6,234,425 | 6,234,425 |
| **System Load** | **22,905,257** | **23,070,734** | **23,252,062** | **23,409,755** | **23,589,075** | **23,767,184** | **23,945,221** | **24,165,313** | **24,326,770** | **24,484,977** |
| **Total Load** | **22,905,257** | **23,070,734** | **23,252,062** | **23,409,755** | **23,589,075** | **23,767,184** | **23,945,221** | **24,165,313** | **24,326,770** | **24,484,977** |
| **Generation Month Sales (MWh) 70th Percentile** | | | | | | | | | | |
| Residential | 6,704,206 | 6,763,302 | 6,832,534 | 6,906,651 | 6,976,408 | 7,039,015 | 7,098,397 | 7,157,159 | 7,215,024 | 7,268,947 |
| Commercial | 4,752,832 | 4,800,574 | 4,833,665 | 4,873,707 | 4,920,067 | 4,971,129 | 5,014,314 | 5,058,800 | 5,096,708 | 5,134,882 |
| Irrigation | 2,211,669 | 2,226,412 | 2,241,694 | 2,257,294 | 2,272,705 | 2,288,412 | 2,304,058 | 2,319,755 | 2,335,307 | 2,350,312 |
| Industrial | 3,075,030 | 3,117,832 | 3,161,475 | 3,206,023 | 3,254,544 | 3,304,634 | 3,354,811 | 3,404,644 | 3,454,735 | 3,505,562 |
| Additional Firm | 6,171,167 | 6,172,006 | 6,193,102 | 6,177,196 | 6,176,327 | 6,173,887 | 6,183,582 | 6,234,425 | 6,234,425 | 6,234,425 |
| **System Sales** | **22,914,904** | **23,080,126** | **23,262,469** | **23,420,870** | **23,600,052** | **23,777,076** | **23,955,161** | **24,174,783** | **24,336,199** | **24,494,128** |
| **Total Sales** | **22,914,904** | **23,080,126** | **23,262,469** | **23,420,870** | **23,600,052** | **23,777,076** | **23,955,161** | **24,174,783** | **24,336,199** | **24,494,128** |
| Loss | 1,672,397 | 1,683,411 | 1,695,732 | 1,706,055 | 1,718,046 | 1,729,897 | 1,742,228 | 1,753,939 | 1,764,571 | 1,774,927 |
| **Required Supply** | **24,587,300** | **24,763,537** | **24,958,202** | **25,126,925** | **25,318,098** | **25,506,973** | **25,697,389** | **25,928,722** | **26,100,770** | **26,269,054** |
| **Average Load (aMW) 70th Percentile** | | | | | | | | | | |
| Residential | 765 | 772 | 778 | 788 | 796 | 804 | 808 | 817 | 824 | 830 |
| Commercial | 543 | 548 | 550 | 556 | 562 | 567 | 571 | 577 | 582 | 586 |
| Irrigation | 252 | 254 | 255 | 258 | 259 | 261 | 262 | 265 | 267 | 268 |
| Industrial | 351 | 356 | 360 | 366 | 372 | 377 | 382 | 389 | 394 | 400 |
| Additional Firm | 704 | 705 | 705 | 705 | 705 | 705 | 704 | 712 | 712 | 712 |
| Loss | 191 | 192 | 193 | 195 | 196 | 198 | 198 | 200 | 201 | 203 |
| **System Load** | **2,807** | **2,827** | **2,841** | **2,868** | **2,890** | **2,912** | **2,926** | **2,960** | **2,980** | **2,999** |
| Light Load | 2,568 | 2,586 | 2,599 | 2,624 | 2,644 | 2,663 | 2,676 | 2,707 | 2,725 | 2,743 |
| Heavy Load | 2,987 | 3,008 | 3,023 | 3,052 | 3,075 | 3,098 | 3,114 | 3,149 | 3,171 | 3,191 |
| **Total Load** | **2,807** | **2,827** | **2,841** | **2,868** | **2,890** | **2,912** | **2,926** | **2,960** | **2,980** | **2,999** |
| **Peak Load (MW) 70th Percentile** | | | | | | | | | | |
| System Peak (1 hour) | 4,897 | 4,944 | 4,992 | 5,041 | 5,091 | 5,140 | 5,188 | 5,242 | 5,290 | 5,337 |
| **Total Peak Load** | **4,897** | **4,944** | **4,992** | **5,041** | **5,091** | **5,140** | **5,188** | **5,242** | **5,290** | **5,337** |

# DEMAND-SIDE RESOURCE DATA

## DSM Financial Assumptions

| | |
|---|---|
| **Avoided Levelized Capacity Costs** | |
| Simple Cycle Combustion Turbine (SCCT) | $145.94/kW-year |
| **Financial Assumptions** | |
| Discount rate (weighted average cost of capital) | 7.12% |
| Financial escalation factor | 2.60% |
| **Transmission Losses** | |
| Non-summer secondary losses | 7.60% |
| Summer peak loss | 7.60% |

## Avoided Cost Averages ($/MWh except where noted)

| Year | Summer High-Risk | Summer Medium-Risk | Summer Low-Risk | Winter High-Risk | Winter Medium-Risk | Winter Low-Risk | Off Season Low-Risk |
|---|---|---|---|---|---|---|---|
| 2024 | $53.48 | $49.44 | $30.40 | $46.68 | $41.02 | $38.83 | $26.67 |
| 2025 | $50.90 | $48.25 | $29.61 | $45.80 | $40.92 | $38.37 | $26.31 |
| 2026 | $51.41 | $47.73 | $28.47 | $47.42 | $40.49 | $39.12 | $24.95 |
| 2027 | $74.68 | $70.21 | $44.15 | $65.45 | $53.89 | $53.84 | $33.75 |
| 2028 | $71.72 | $68.19 | $43.44 | $64.02 | $50.61 | $52.15 | $29.52 |
| 2029 | $70.57 | $66.78 | $42.01 | $61.08 | $48.30 | $51.82 | $28.64 |
| 2030 | $70.09 | $65.60 | $40.01 | $62.08 | $48.02 | $53.41 | $26.57 |
| 2031 | $69.60 | $64.72 | $37.52 | $58.34 | $42.29 | $47.89 | $24.03 |
| 2032 | $67.53 | $63.29 | $37.55 | $58.38 | $44.24 | $49.46 | $23.48 |
| 2033 | $72.11 | $67.37 | $39.11 | $57.08 | $41.95 | $49.69 | $23.18 |
| 2034 | $78.99 | $73.32 | $48.68 | $63.30 | $50.37 | $57.11 | $21.97 |
| 2035 | $70.08 | $58.41 | $32.27 | $45.04 | $34.97 | $37.71 | $14.01 |
| 2036 | $93.67 | $64.41 | $18.71 | $45.04 | $32.53 | $30.90 | $13.43 |
| 2037 | $100.50 | $69.86 | $18.99 | $47.41 | $34.84 | $32.96 | $14.37 |
| 2038 | $97.60 | $69.33 | $18.40 | $45.25 | $36.10 | $31.44 | $14.04 |
| 2039 | $92.93 | $63.94 | $18.17 | $41.56 | $32.90 | $27.96 | $13.58 |
| 2040 | $91.36 | $57.96 | $14.39 | $34.69 | $26.68 | $23.99 | $10.87 |
| 2041 | $97.19 | $61.51 | $14.48 | $36.95 | $29.42 | $25.26 | $10.83 |
| 2042 | $107.97 | $65.06 | $14.97 | $36.62 | $28.19 | $23.43 | $11.15 |
| 2043 | $98.25 | $60.65 | $12.47 | $34.86 | $26.94 | $23.43 | $10.86 |

The time periods used to develop the avoided cost averages presented in the table above align with the company’s highest-risk hours, which are described in the Loss of Load Expectation section.

# Bundle Amounts

## Incremental Achievable Potential (aMW)

| Bundle | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| Summer Low | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 |
| Summer Medium | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 |
| Summer High | 0 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 |
| Winter Low | 1 | 2 | 2 | 3 | 3 | 4 | 3 | 3 | 3 | 3 |
| Winter High | 0 | 1 | 1 | 2 | 2 | 2 | 3 | 3 | 3 | 3 |
| **Total** | **4** | **5** | **7** | **8** | **10** | **11** | **11** | **12** | **13** | **13** |

| Bundle | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|
| Summer Low | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Summer Medium | 1 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 |
| Summer High | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Winter Low | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Winter High | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| **Total** | **13** | **13** | **14** | **14** | **14** | **14** | **15** | **15** | **15** | **15** |

# Bundle Costs

## Savings Weighted Levelized Cost of Energy ($/MWh) Real Dollars

| Bundle | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| Summer Low | $91 | $94 | $96 | $98 | $100 | $99 | $99 | $97 | $97 | $99 |
| Summer Medium | $336 | $334 | $333 | $330 | $326 | $321 | $316 | $310 | $307 | $302 |
| Summer High | $948 | $873 | $860 | $835 | $807 | $772 | $749 | $725 | $711 | $648 |
| Winter Low | $85 | $84 | $84 | $83 | $82 | $80 | $77 | $74 | $71 | $68 |
| Winter High | $632 | $592 | $559 | $540 | $514 | $482 | $466 | $432 | $405 | $382 |
| **Total** | **$2,091** | **$1,977** | **$1,933** | **$1,886** | **$1,829** | **$1,754** | **$1,707** | **$1,639** | **$1,591** | **$1,500** |

| Bundle | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|
| Summer Low | $100 | $99 | $98 | $97 | $95 | $93 | $92 | $90 | $89 | $88 |
| Summer Medium | $300 | $298 | $295 | $293 | $291 | $289 | $287 | $286 | $285 | $284 |
| Summer High | $643 | $640 | $629 | $615 | $581 | $555 | $535 | $519 | $510 | $495 |
| Winter Low | $365 | $350 | $335 | $315 | $289 | $277 | $255 | $237 | $236 | $224 |
| Winter High | $66 | $64 | $61 | $59 | $56 | $54 | $52 | $52 | $52 | $52 |
| **Total** | **$1,473** | **$1,450** | **$1,419** | **$1,379** | **$1,313** | **$1,267** | **$1,221** | **$1,185** | **$1,173** | **$1,143** |

# 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 | 2.60% |
| Annual property tax rate (% of investment) | 0.44% |
| B2H annual property tax rate (% of investment) | 0.70% |
| Property tax escalation rate | 3.00% |
| B2H property tax escalation rate | 1.05% |
| Annual insurance premiums (% of investment) | 0.046% |
| B2H annual insurance premiums (% of investment) | 0.003% |
| Insurance escalation rate | 5.00% |
| B2H insurance escalation rate | 5.00% |
| AFUDC rate (annual) | 7.50% |

[1] Incorporates tax effects.

## Cost Inputs and Operating Assumptions (Costs in 2024$)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital[1] ($/kW) | Transmission/Interconnection Capital ($/kW) | Total Capital ($/kW) | Fixed O&M[2] ($/kW-month) | Variable O&M ($/MWh) | Heat Rate (Btu/kWh) | Economic Life (years) |
|---|---|---|---|---|---|---|---|---|
| Baseload Gas—Combined-Cycle Combustion Turbine (CCCT) | 300 | $1,450 | $140 | $1,590 | $1.40 | $3.10 | 6,363 | 30 |
| Biomass | 30 | $4,770 | $167 | $4,937 | $15.10 | $7.00 | 13,500 | 30 |
| Clean Peaking Gas—Hydrogen Combustion Turbine | 170 | $940 | $81 | $1,021 | $2.10 | $6.00 | 9,717 | 35 |
| Danskin 1 Retrofit—Simple-Cycle Combustion Turbine (SCCT) to CCCT Conversion | 90 | $2,530 | $94 | $2,624 | $1.40 | $3.10 | 6,909 | 30 |
| Geothermal | 30 | $5,150 | $167 | $5,317 | $10.40 | $0.00 | 0 | 30 |
| Long-Duration Storage—Pumped Hydro (12 hour) | 250 | $3,710 | $207 | $3,917 | $1.80 | $0.60 | 0 | 75 |
| Medium-Duration Storage—Li Battery (8 hour) | 50 | $2,500 | $37 | $2,537 | $5.20 | $0.00 | 0 | 20 |
| Multi-Day-Duration Storage—Iron-Air Battery (100 hour) | 50 | $2,400 | $37 | $2,437 | $1.80 | $0.00 | 0 | 30 |
| Nuclear—Small Modular Reactor | 100 | $7,960 | $174 | $8,134 | $11.40 | $4.30 | 10,461 | 60 |
| Peaking Gas—Reciprocating Gas Engine (Recip) | 50 | $1,880 | $81 | $1,961 | $3.50 | $6.80 | 8,699 | 40 |
| Peaking Gas—SCCT | 170 | $910 | $81 | $991 | $2.10 | $6.00 | 9,717 | 35 |
| Short-Duration Storage—Li Battery (4 hour) | 50 | $1,600 | $37 | $1,637 | $2.90 | $0.00 | 0 | 20 |
| Short-Duration Storage—Li Battery (4 hour)—Distribution Connected | 5 | $1,440 | $40 | $1,480 | $2.90 | $0.00 | 0 | 20 |
| Solar PV | 100 | $1,200 | $22 | $1,222 | $1.90 | $0.00 | 0 | 30 |
| Wind—Idaho | 100 | $1,760 | $22 | $1,782 | $4.10 | $0.00 | 0 | 30 |
| Wind—Wyoming | 100 | $1,760 | $22 | $1,782 | $4.10 | $0.00 | 0 | 30 |

[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).

## Supply-Side Resource Escalation Factors[1] (2024–2032)

| Supply-Side Resources | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|
| Baseload Gas—Combined-Cycle Combustion Turbine (CCCT) | | 1.68% | 1.90% | 1.78% | 2.01% | 2.00% | 2.24% | 2.00% | 2.24% |
| Biomass | | 1.94% | 1.95% | 1.95% | 1.94% | 1.94% | 1.94% | 1.93% | 1.93% |
| Clean Peaking Gas—Hydrogen Combustion Turbine | | 0.76% | 1.53% | 1.24% | 1.78% | 1.77% | 2.04% | 1.90% | 2.03% |
| Danskin 1 Retrofit—Simple-Cycle Combustion Turbine (SCCT) to CCCT Conversion | | 1.68% | 1.90% | 1.78% | 2.01% | 2.00% | 2.24% | 2.00% | 2.24% |
| Geothermal | | 1.07% | 1.05% | 1.02% | 1.00% | 0.97% | 0.94% | 2.10% | 2.10% |
| Long-Duration Storage—Pumped Hydro (12 hour) | | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% |
| Medium-Duration Storage—Li Battery (8 hour) | | 0.00% | -2.56% | -2.14% | -2.68% | -2.35% | -2.12% | 1.39% | 1.33% |
| Multi-Day-Duration Storage—Iron-Air Battery (100 hour) | | 0.00% | -2.56% | -2.14% | -2.68% | -2.35% | -2.12% | 1.39% | 1.33% |
| Nuclear—Small Modular Reactor | | 1.96% | 1.95% | 1.95% | 1.95% | 1.94% | 1.94% | 1.93% | 1.93% |
| Peaking Gas—Reciprocating Gas Engine (Recip) | | 0.76% | 1.53% | 1.24% | 1.78% | 1.77% | 2.04% | 1.90% | 2.03% |
| Peaking Gas—SCCT | | 0.76% | 1.53% | 1.24% | 1.78% | 1.77% | 2.04% | 1.90% | 2.03% |
| Short-Duration Storage—Li Battery (4 hour) | | 0.00% | -1.67% | -1.36% | -2.04% | -1.18% | -1.33% | 1.40% | 1.33% |
| Short-Duration Storage—Li Battery (4 hour)—Distribution Connected | | 0.00% | -1.67% | -1.36% | -2.04% | -1.18% | -1.33% | 1.40% | 1.33% |
| Solar PV | | -1.88% | -2.09% | -2.32% | -2.57% | -2.86% | -3.17% | 1.71% | 1.70% |
| Wind—Idaho | | -1.47% | -1.65% | -1.83% | -2.04% | -2.27% | -2.51% | 1.60% | 1.59% |
| Wind—Wyoming | | -1.47% | -1.65% | -1.83% | -2.04% | -2.27% | -2.51% | 1.60% | 1.59% |

[1] Factors include the 2023 IRP general O&M escalation rate assumption of 2.6%.

## Supply-Side Resource Escalation Factors[1] (2033–2043)

| Supply-Side Resources | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Baseload Gas—Combined-Cycle Combustion Turbine (CCCT) | 2.11% | 2.23% | 2.11% | 2.23% | 2.11% | 2.23% | 2.10% | 2.22% | 2.22% | 2.10% | 2.22% |
| Biomass | 1.92% | 1.92% | 1.91% | 1.91% | 1.90% | 1.90% | 1.89% | 1.89% | 1.88% | 1.88% | 1.87% |
| Clean Peaking Gas—Hydrogen Combustion Turbine | 2.03% | 2.17% | 2.03% | 2.02% | 2.02% | 2.16% | 2.01% | 2.01% | 2.01% | 2.15% | 2.00% |
| Danskin 1 Retrofit—Simple-Cycle Combustion Turbine (SCCT) to CCCT Conversion | 2.11% | 2.23% | 2.11% | 2.23% | 2.11% | 2.23% | 2.10% | 2.22% | 2.22% | 2.10% | 2.22% |
| Geothermal | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% | 2.10% |
| Long-Duration Storage—Pumped Hydro (12 hour) | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% | 2.60% |
| Medium-Duration Storage—Li Battery (8 hour) | 1.32% | 1.30% | 1.28% | 1.27% | 1.25% | 1.23% | 1.21% | 1.19% | 1.17% | 1.15% | 1.13% |
| Multi-Day-Duration Storage—Iron-Air Battery (100 hour) | 1.32% | 1.30% | 1.28% | 1.27% | 1.25% | 1.23% | 1.21% | 1.19% | 1.17% | 1.15% | 1.13% |
| Nuclear—Small Modular Reactor | 1.92% | 1.92% | 1.92% | 1.91% | 1.91% | 1.90% | 1.90% | 1.89% | 1.89% | 1.88% | 1.88% |
| Peaking Gas—Reciprocating Gas Engine (Recip) | 2.03% | 2.17% | 2.03% | 2.02% | 2.02% | 2.16% | 2.01% | 2.01% | 2.01% | 2.15% | 2.00% |
| Peaking Gas—SCCT | 2.03% | 2.17% | 2.03% | 2.02% | 2.02% | 2.16% | 2.01% | 2.01% | 2.01% | 2.15% | 2.00% |
| Short-Duration Storage—Li Battery (4 hour) | 1.32% | 1.30% | 1.28% | 1.27% | 1.25% | 1.23% | 1.21% | 1.19% | 1.17% | 1.15% | 1.13% |
| Short-Duration Storage—Li Battery (4 hour)—Distribution Connected | 1.32% | 1.30% | 1.28% | 1.27% | 1.25% | 1.23% | 1.21% | 1.19% | 1.17% | 1.15% | 1.13% |
| Solar PV | 1.69% | 1.68% | 1.68% | 1.67% | 1.66% | 1.65% | 1.64% | 1.63% | 1.62% | 1.61% | 1.60% |
| Wind—Idaho | 1.58% | 1.57% | 1.56% | 1.55% | 1.54% | 1.52% | 1.51% | 1.50% | 1.49% | 1.48% | 1.46% |
| Wind—Wyoming | 1.58% | 1.57% | 1.56% | 1.55% | 1.54% | 1.52% | 1.51% | 1.50% | 1.49% | 1.48% | 1.46% |

[1] Factors include the 2023 IRP general O&M escalation rate assumption of 2.6%.

## Levelized Cost of Energy (costs in 2024$, $/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 |
|---|---|---|---|---|---|
| Baseload Gas—Combined-Cycle Combustion Turbine (CCCT) | $36 | $12 | $42 | $89 | 55% |
| Biomass | $65 | $61 | $110 | $236 | 64% |
| Clean Peaking Gas—Hydrogen Combustion Turbine | $68 | $50 | $191 | $309 | 12% |
| Danskin 1 Retrofit—Simple-Cycle Combustion Turbine (SCCT) to CCCT Conversion | $56 | $13 | $46 | $115 | 55% |
| Geothermal | $50 | $27 | $0 | $78 | 90% |
| Long-Duration Storage—Pumped Hydro (12 hour) | $82 | $17 | $0 | $99 | 50% |
| Medium-Duration Storage—Li Battery (8 hour) | $77 | $33 | $0 | $111 | 33% |
| Multi-Day-Duration Storage—Iron-Air Battery (100 hour) | $148 | $36 | $0 | $184 | 15% |
| Nuclear—Small Modular Reactor | $83 | $42 | $13 | $139 | 94% |
| Peaking Gas—Reciprocating Gas Engine (Recip) | $188 | $83 | $61 | $332 | 12% |
| Peaking Gas—SCCT | $98 | $50 | $66 | $214 | 12% |
| Short-Duration Storage—Li Battery (4 hour) | $97 | $37 | $0 | $134 | 17% |
| Short-Duration Storage—Li Battery (4 hour)—Distribution Connected | $88 | $36 | $0 | $124 | 17% |
| Solar PV | $17 | $15 | $0 | $31 | 31% |
| Wind—Idaho | $28 | $25 | $0 | $53 | 36% |
| Wind—Wyoming | $16 | $19 | $0 | $35 | 47% |

[1] Cost of Capital includes tax credit benefits (ITC/PTC).
[2] Non-Fuel O&M includes fixed 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] Rounding may make the sum of Capital, Non-Fuel O&M and Fuel not match the total cost per MWh.

## Levelized Capacity (fixed) Cost per kW/Month (costs in 2024$)

| Supply-Side Resources | Cost of Capital[1] | Non-Fuel O&M[2] | Total Cost per kW[3] |
|---|---|---|---|
| Baseload Gas—Combined-Cycle Combustion Turbine (CCCT) | $14 | $3 | $17 |
| Biomass | $31 | $24 | $54 |
| Clean Peaking Gas—Hydrogen Combustion Turbine | $8 | $4 | $12 |
| Danskin 1 Retrofit—Simple-Cycle Combustion Turbine (SCCT) to CCCT Conversion | $23 | $4 | $26 |
| Geothermal | $33 | $18 | $51 |
| Long-Duration Storage—Pumped Hydro (12 hour) | $30 | $6 | $36 |
| Medium-Duration Storage—Li Battery (8 hour) | $19 | $8 | $27 |
| Multi-Day-Duration Storage—Iron-Air Battery (100 hour) | $16 | $4 | $20 |
| Nuclear—Small Modular Reactor | $57 | $25 | $82 |
| Peaking Gas—Reciprocating Gas Engine (Recip) | $16 | $6 | $23 |
| Peaking Gas—SCCT | $9 | $4 | $12 |
| Short-Duration Storage—Li Battery (4 hour) | $12 | $5 | $17 |
| Short-Duration Storage—Li Battery (4 hour)—Distribution Connected | $11 | $4 | $15 |
| Solar PV | $4 | $3 | $7 |
| Wind—Idaho | $7 | $7 | $14 |
| Wind—Wyoming | $5 | $7 | $12 |

[1] Cost of Capital includes tax credit benefits (ITC/PTC).

[2] Non-Fuel O&M includes fixed and property taxes.

[3] Rounding may make sum of Cost of Capital and Non-Fuel O&M costs not match Total Cost per kW.

## Renewable Energy Certificate Forecast

| Year | Nominal ($/MWh) |
|---|---|
| 2024 | $22.07 |
| 2025 | $20.10 |
| 2026 | $20.58 |
| 2027 | $21.06 |
| 2028 | $21.54 |
| 2029 | $22.01 |
| 2030 | $22.49 |
| 2031 | $22.97 |
| 2032 | $23.45 |
| 2033 | $23.93 |
| 2034 | $24.40 |
| 2035 | $24.88 |
| 2036 | $25.36 |
| 2037 | $25.84 |
| 2038 | $26.32 |
| 2039 | $26.79 |
| 2040 | $27.27 |
| 2041 | $27.75 |
| 2042 | $28.23 |
| 2043 | $28.71 |

# EXISTING RESOURCE DATA

## Qualifying Facility Data (PURPA)

### *Cogeneration & Small Power Production Projects*

### *Status as of July 31, 2023*

### Hydro Projects

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Little Wood River Ranch II | 1.25 | Oct-2015 | Oct-2035 |
| Baker City Hydro | 0.24 | Sep-2015 | Sep-2030 | Little Wood River Res | 2.85 | Mar-2020 | Mar-2040 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Low Line Canal | 8.20 | May-2020 | May-2040 |
| Birch Creek | 0.07 | Nov-2019 | Nov-2039 | Low Line Midway Hydro | 2.50 | Aug-2007 | Aug-2027 |
| Black Canyon #3 | 0.13 | Apr-2019 | Apr-2039 | Lowline #2 | 2.79 | May-2023 | May-2043 |
| Black Canyon Bliss Hydro | 0.03 | Oct-2015 | Oct-2035 | Magic Reservoir | 9.07 | Jun-1989 | Jun-2024 |
| Blind Canyon | 1.63 | Dec-2014 | Dec-2034 | Malad River | 1.17 | May-2019 | May-2039 |
| Box Canyon | 0.30 | Feb-2019 | Feb-2039 | Marco Ranches | 1.20 | Aug-2020 | Aug-2040 |
| Briggs Creek | 0.60 | Oct-2020 | Oct-2040 | MC6 Hydro | 2.30 | Apr-2021 | Sep-2040 |
| Bypass | 9.96 | Jun-2023 | Jun-2043 | Mile 28 | 1.50 | Jun-1994 | Jun-2029 |
| Canyon Springs | 0.11 | Jan-2019 | Jan-2039 | Mitchell Butte | 2.09 | May-1989 | Dec-2034 |
| Cedar Draw | 1.55 | Jun-2019 | Jun-2039 | Mora Drop Small Hydro | 1.85 | Sep-2006 | Sep-2026 |
| Clear Springs Trout | 0.56 | Nov-2018 | Nov-2038 | Mud Creek/S&S | 0.52 | Feb-2017 | Feb-2037 |
| Coleman Hydro | 0.80 | Sep-2023 | Estimated | Mud Creek/White | 0.29 | Jan-2021 | Jan-2041 |
| Crystal Springs | 2.55 | Apr-2021 | Apr-2041 | North Gooding Main Hydro | 1.30 | Oct-2016 | Oct-2036 |
| Curry Cattle Company | 0.25 | Jun-2018 | Jun-2033 | Owyhee Dam CSPP | 5.00 | Aug-1985 | May-2034 |
| Dietrich Drop | 4.77 | Sep-2023 | Sep-2043 | Pigeon Cove | 1.75 | Nov-2019 | Nov-2039 |
| Eightmile Hydro Project | 0.36 | Oct-2014 | Oct-2034 | Pristine Springs #1 | 0.13 | May-2020 | May-2040 |
| Elk Creek Hydro | 2.35 | Jun-2021 | Apr-2041 | Pristine Springs #3 | 0.20 | May-2020 | May-2040 |
| Fall River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.35 | Sep-2021 | Sep-2041 |
| Fargo Drop Hydroelectric | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.17 | Jan-2018 | Jan-2038 |
| Faulkner Ranch Hydro | 0.87 | Aug-2022 | Aug-2042 | Rock Creek #2 | 1.90 | Apr-1989 | Apr-2024 |
| Fisheries Dev. | 0.26 | Jul-1990 | Jul-2040 | Sagebrush | 0.58 | Jun-2021 | Jun-2040 |
| Geo-Bon #2 | 1.06 | Nov-2021 | Nov-2041 | Sahko Hydro | 0.50 | Feb-2021 | Feb-2041 |
| Hailey CSPP | 0.04 | Jun-2020 | Jun-2025 | Shingle Creek | 0.22 | Aug-2022 | Aug-2027 |
| Hazelton A | 8.10 | Mar-2011 | Feb-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 | Jun-2015 | Jun-2035 | Snake River Pottery | 0.09 | Dec-2019 | Dec-2027 |
| Horseshoe Bend Hydro | 9.50 | Sep-1995 | Sep-2030 | Snedigar | 0.50 | Jan-2020 | Jan-2040 |
| Jim Knight | 0.48 | May-2021 | May-2040 | Tiber Dam | 7.50 | Jun-2004 | Jun-2024 |
| Koyle Small Hydro | 1.25 | Apr-2019 | Apr-2039 | Trout-Co | 0.28 | Dec-2021 | Dec-2041 |
| Lateral # 10 | 2.06 | May-2020 | May-2040 | Tunnel #1 | 7.00 | Jun-1993 | Jun-2036 |
| Lemhi Hydro | 0.45 | Aug-2021 | Aug-2041 | White Water Ranch | 0.16 | Aug-2020 | Aug-2040 |
| LeMoyne Hydro | 0.08 | Jun-2020 | Jun-2030 | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| Little Wood River Ranch I | 1.01 | Aug-2021 | Aug-2041 | | | | |
| **Total Hydro Nameplate Rating 151.32 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-2022 | Mar-2025 |
| 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 | 0.50 | Jan-2021 | Jan-2041 |
| Fighting Creek Landfill Gas to Energy Station | 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 21.21 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 | Apr-2017 | Apr-2037 |
| Baker Solar Center | 15.00 | Feb-2020 | Feb-2040 | Ontario Solar Center | 3.00 | Mar-2020 | Mar-2040 |
| Brush Solar | 2.75 | Dec-2019 | Dec-2039 | Open Range Solar Center, LLC | 10.00 | Oct-2016 | Oct-2036 |
| Durkee Solar | 3.00 | Dec-2024 | Mar-2042 | Orchard Ranch Solar, LLC | 20.00 | Mar-2017 | Mar-2037 |
| Grand View PV Solar Two | 80.00 | Dec-2016 | Dec-2036 | Prairie City Solar | 29.30 | Dec-2024 | Estimated |
| Grove Solar Center, LLC | 6.00 | Oct-2016 | Oct-2036 | Railroad Solar Center, LLC | 4.50 | Dec-2016 | Dec-2036 |
| Hyline Solar Center, LLC | 9.00 | Nov-2016 | Nov-2036 | Simcoe Solar, LLC | 20.00 | Mar-2017 | Mar-2037 |
| ID Solar 1 | 40.00 | Aug-2016 | Jan-2036 | Thunderegg Solar Center, LLC | 10.00 | Nov-2016 | Nov-2036 |
| Moore's Hollow Solar | 42.00 | Dec-2024 | Estimated | 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 390.55 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 | 8.40 | 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 624.82 MW** | | | | | | | |
| **Total Nameplate Rating 1,210.90 MW** | | | | | | | |

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of July 31, 2023. 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** | | | |
| Black Mesa Solar | 40 | Jun-2023 | Jun-2043 |
| Franklin Solar | 100 | Jun-2024 | Jun-2049 |
| Jackpot Solar Facility | 120 | Dec-2022 | Dec-2042 |
| Pleasant Valley Solar | 200 | Mar-2025 | Mar-2045 |
| **Total Solar Nameplate Rating** | **460** | | |
| **Total Nameplate Rating** | **596** | | |

The above is a summary of the Nameplate rating for the projects under contract with Idaho Power as of July 31, 2023. In the case of variable-energy resource 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 for the development of future hydro flow scenarios for the IRP. The first method accounts for surface water regulation in the system while the second method addresses groundwater processes.

The first modeling method consists of two models built in the Center for Advanced Decision Support for Water and Environmental Systems (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 planning models have been updated to include hydrologic conditions for water years 1981 through 2018.

The second modeling method uses the Eastern Snake Plain Aquifer Model (ESPAM) from the Idaho Department of Water Resources (IDWR) to model aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). ESPAM version 2.2 has been used for this modeling, which is the latest version and was released in 2020.

### *Hydro Model Inputs*

The inputs for the 2023 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, irrigation system conversions from groundwater to surface water, and a total reduction in groundwater diversions of 240,000 acre-ft annually. The modeling also included inputs from other entities diverting groundwater on the ESPA who have separate mitigation agreements with 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 by the Idaho Water Resource Board (IWRB) targeting an average annual natural flow recharge of 250,000 acre-ft per year.

Recharge capacity modeled for the 2023 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.

The number of system conversion acres modeled and associated water savings was based on data provided by IDWR and local groundwater 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 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 an approximately 140,000 acre-ft decrease in groundwater pumping from ESPA. These reflect the same assumptions of conversion projects as modeled in the 2021 IRP.

The decrease was spread evenly over groundwater irrigated lands subject to the agreement between SWC and IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft/year, but the agreement allows for a portion to be offset by aquifer recharge activities. Based on recent management activity, an approximate 100,000 acre-ft/year reduction is accomplished through other forms of mitigation, such as private aquifer recharge.

The 2023 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using statistical analysis. Trend data indicate reach gains from Blackfoot to Neely and from Lower Salmon Falls Dam to King Hill demonstrated a statistically significant decline from 1992 to 2021. The long-term declines are still present, and are relatively the same as the declines used in the 2021 IRP.

Weather modification was added to the model at various levels of development. For IRP years 2024 through 2029, weather modification reflects the 2022 level of program development in the Upper Snake, Wood, Boise, and Payette river basins. From IRP year 2030 and onward, weather modification levels in Upper Snake, Wood, and Boise river 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 horizon. The modeling also accounts for changes in reach gains from observed water management activities on the ESPA since 2014. Idaho Power used data from IDWR and other sources to determine the magnitude of the management activities and ESPAM was used to model the projected reach gains. Those management activities can have impacts on reach gains for up to 30 years.

### *Hydro Model Results*

Overall inflow to Brownlee Reservoir increases from IRP modeled year 2024 through 2031. Flows peak in 2031 with the 50% exceedance water year annual inflow to Brownlee Reservoir at 11.9 million acre-ft/year. In 2043, those flows declined to approximately 11.8 million acre-ft/year.

The Brownlee inflow volumes for the 2023 IRP are lower than those reported in the 2021 IRP. There are several factors leading to the decrease in modeled flows. Updates to recharge capacity to reflect current infrastructure availability and capacities was likely the largest impact. While this does have some improvement in the modeled aquifer health and reach gains, the surface water impacts, reducing releases at Milner, significantly outweigh the groundwater impacts over the 20-year planning window. Another notable change was the use of ESPAM 2.2, which has a better calibration of the groundwater system, and reduced aquifer response below Milner which better reflects observations over the last several years. As a result, groundwater management activities produce lower reach gains throughout Idaho Power's hydro system.

## Hydro Modeling Potential Energy Limits (aMW)

| | | 50th Percentile (planning case) | | | Extreme Weather Scenario | | |
|---|---|---|---|---|---|---|---|
| Year | Month | HCC | ROR | Total | HCC | ROR | Total |
| 2024 | Jan | 642 | 276 | 917 | 1155 | 505 | 1,660 |
| | Feb | 828 | 291 | 1,119 | 1151 | 474 | 1,625 |
| | Mar | 739 | 339 | 1,078 | 990 | 505 | 1,494 |
| | Apr | 873 | 355 | 1,229 | 1093 | 527 | 1,620 |
| | May | 894 | 328 | 1,222 | 1131 | 531 | 1,662 |
| | June | 846 | 362 | 1,208 | 1224 | 489 | 1,713 |
| | July | 567 | 371 | 938 | 902 | 403 | 1,305 |
| | Aug | 457 | 283 | 741 | 646 | 420 | 1,065 |
| | Sept | 508 | 236 | 744 | 737 | 260 | 998 |
| | Oct | 388 | 213 | 601 | 446 | 236 | 682 |
| | Nov | 339 | 184 | 522 | 330 | 205 | 535 |
| | Dec | 457 | 178 | 635 | 625 | 378 | 1,003 |
| **Annual aMW** | | **628** | **285** | **913** | **869** | **411** | **1,280** |
| 2025 | Jan | 645 | 279 | 925 | 1185 | 497 | 1,683 |
| | Feb | 831 | 294 | 1,125 | 1129 | 474 | 1,603 |
| | Mar | 741 | 340 | 1,081 | 954 | 504 | 1,458 |
| | Apr | 874 | 357 | 1,231 | 934 | 505 | 1,439 |
| | May | 895 | 331 | 1,226 | 1047 | 513 | 1,560 |
| | June | 847 | 363 | 1,210 | 1253 | 515 | 1,767 |
| | July | 568 | 373 | 940 | 844 | 397 | 1,241 |
| | Aug | 458 | 284 | 742 | 670 | 434 | 1,104 |
| | Sept | 509 | 236 | 745 | 696 | 263 | 959 |
| | Oct | 388 | 214 | 602 | 408 | 236 | 644 |
| | Nov | 339 | 184 | 523 | 328 | 203 | 530 |
| | Dec | 458 | 178 | 636 | 649 | 431 | 1,080 |
| **Annual aMW** | | **629** | **286** | **915** | **841** | **414** | **1,256** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2026 | Jan | 647 | 282 | 929 | 1104 | 497 | 1,601 |
| | Feb | 833 | 296 | 1,130 | 1077 | 467 | 1,544 |
| | Mar | 744 | 340 | 1,084 | 1069 | 385 | 1,454 |
| | Apr | 874 | 358 | 1,232 | 1127 | 475 | 1,602 |
| | May | 895 | 331 | 1,227 | 915 | 499 | 1,414 |
| | June | 848 | 363 | 1,211 | 897 | 415 | 1,312 |
| | July | 568 | 373 | 941 | 624 | 402 | 1,025 |
| | Aug | 458 | 284 | 742 | 463 | 285 | 748 |
| | Sept | 509 | 237 | 745 | 616 | 243 | 858 |
| | Oct | 388 | 214 | 602 | 391 | 225 | 617 |
| | Nov | 339 | 184 | 523 | 334 | 193 | 527 |
| | Dec | 459 | 178 | 637 | 447 | 182 | 629 |
| **Annual aMW** | | **630** | **287** | **917** | **755** | **356** | **1,111** |
| 2027 | Jan | 648 | 283 | 931 | 543 | 261 | 805 |
| | Feb | 834 | 298 | 1,132 | 587 | 252 | 840 |
| | Mar | 744 | 341 | 1,085 | 520 | 281 | 800 |
| | Apr | 874 | 359 | 1,233 | 544 | 223 | 767 |
| | May | 895 | 332 | 1,227 | 533 | 230 | 763 |
| | June | 848 | 364 | 1,211 | 510 | 355 | 865 |
| | July | 568 | 373 | 941 | 474 | 273 | 747 |
| | Aug | 458 | 284 | 742 | 403 | 211 | 614 |
| | Sept | 509 | 237 | 746 | 409 | 195 | 604 |
| | Oct | 388 | 214 | 602 | 350 | 194 | 544 |
| | Nov | 339 | 184 | 523 | 339 | 175 | 514 |
| | Dec | 459 | 179 | 638 | 427 | 169 | 596 |
| **Annual aMW** | | **630** | **287** | **918** | **470** | **235** | **705** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2028 | Jan | 649 | 283 | 932 | 548 | 171 | 719 |
| | Feb | 835 | 300 | 1,135 | 582 | 169 | 751 |
| | Mar | 745 | 342 | 1,087 | 600 | 181 | 781 |
| | Apr | 874 | 360 | 1,234 | 859 | 200 | 1,058 |
| | May | 895 | 332 | 1,227 | 649 | 279 | 928 |
| | June | 848 | 364 | 1,212 | 740 | 239 | 979 |
| | July | 568 | 373 | 941 | 487 | 262 | 750 |
| | Aug | 458 | 284 | 742 | 417 | 215 | 631 |
| | Sept | 509 | 237 | 745 | 383 | 197 | 581 |
| | Oct | 388 | 214 | 602 | 358 | 193 | 551 |
| | Nov | 339 | 184 | 523 | 345 | 176 | 521 |
| | Dec | 460 | 179 | 638 | 424 | 170 | 595 |
| **Annual aMW** | | **631** | **288** | **918** | **533** | **204** | **737** |
| 2029 | Jan | 650 | 283 | 933 | 577 | 176 | 753 |
| | Feb | 832 | 301 | 1,133 | 682 | 178 | 860 |
| | Mar | 743 | 342 | 1,085 | 503 | 176 | 679 |
| | Apr | 874 | 360 | 1,234 | 713 | 230 | 943 |
| | May | 892 | 332 | 1,224 | 958 | 241 | 1,199 |
| | June | 839 | 363 | 1,203 | 860 | 238 | 1,098 |
| | July | 567 | 371 | 938 | 501 | 345 | 846 |
| | Aug | 460 | 284 | 744 | 421 | 249 | 669 |
| | Sept | 508 | 237 | 745 | 370 | 216 | 586 |
| | Oct | 388 | 214 | 602 | 359 | 195 | 554 |
| | Nov | 339 | 184 | 523 | 349 | 174 | 523 |
| | Dec | 460 | 179 | 639 | 416 | 171 | 587 |
| **Annual aMW** | | **629** | **288** | **917** | **559** | **216** | **775** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2030 | Jan | 710 | 288 | 998 | 535 | 202 | 737 |
| | Feb | 850 | 325 | 1,176 | 687 | 214 | 901 |
| | Mar | 795 | 348 | 1,143 | 722 | 257 | 979 |
| | Apr | 883 | 380 | 1,263 | 794 | 268 | 1,062 |
| | May | 926 | 362 | 1,288 | 728 | 233 | 961 |
| | June | 880 | 381 | 1,261 | 654 | 261 | 915 |
| | July | 573 | 376 | 949 | 567 | 333 | 900 |
| | Aug | 463 | 288 | 751 | 452 | 217 | 670 |
| | Sept | 511 | 238 | 749 | 462 | 199 | 661 |
| | Oct | 388 | 215 | 603 | 375 | 187 | 563 |
| | Nov | 339 | 185 | 523 | 331 | 170 | 501 |
| | Dec | 464 | 180 | 644 | 446 | 166 | 612 |
| **Annual aMW** | | **649** | **297** | **946** | **563** | **226** | **788** |
| 2031 | Jan | 714 | 290 | 1,003 | 489 | 169 | 658 |
| | Feb | 849 | 327 | 1,177 | 508 | 161 | 669 |
| | Mar | 796 | 350 | 1,146 | 378 | 162 | 540 |
| | Apr | 884 | 382 | 1,266 | 559 | 229 | 788 |
| | May | 926 | 365 | 1,291 | 926 | 315 | 1,241 |
| | June | 882 | 381 | 1,263 | 701 | 283 | 984 |
| | July | 573 | 376 | 949 | 586 | 382 | 968 |
| | Aug | 463 | 288 | 752 | 451 | 277 | 727 |
| | Sept | 511 | 239 | 750 | 455 | 225 | 680 |
| | Oct | 388 | 215 | 603 | 366 | 202 | 568 |
| | Nov | 339 | 185 | 523 | 347 | 171 | 518 |
| | Dec | 464 | 180 | 644 | 616 | 172 | 788 |
| **Annual aMW** | | **649** | **298** | **947** | **532** | **229** | **761** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2032 | Jan | 714 | 290 | 1,004 | 1123 | 292 | 1,415 |
| | Feb | 847 | 327 | 1,174 | 1086 | 225 | 1,310 |
| | Mar | 801 | 350 | 1,151 | 1045 | 422 | 1,467 |
| | Apr | 885 | 391 | 1,276 | 1050 | 513 | 1,562 |
| | May | 926 | 366 | 1,292 | 1152 | 514 | 1,667 |
| | June | 882 | 381 | 1,263 | 1173 | 468 | 1,640 |
| | July | 573 | 376 | 949 | 633 | 420 | 1,053 |
| | Aug | 463 | 289 | 752 | 488 | 289 | 778 |
| | Sept | 511 | 239 | 750 | 563 | 239 | 802 |
| | Oct | 388 | 215 | 603 | 389 | 211 | 600 |
| | Nov | 339 | 185 | 524 | 337 | 177 | 514 |
| | Dec | 464 | 180 | 644 | 480 | 172 | 652 |
| **Annual aMW** | | **649** | **299** | **948** | **793** | **328** | **1,122** |
| 2033 | Jan | 714 | 290 | 1,004 | 575 | 287 | 862 |
| | Feb | 848 | 328 | 1,177 | 685 | 312 | 997 |
| | Mar | 796 | 350 | 1,146 | 614 | 366 | 980 |
| | Apr | 884 | 382 | 1,266 | 622 | 292 | 913 |
| | May | 926 | 363 | 1,289 | 670 | 238 | 908 |
| | June | 881 | 382 | 1,263 | 524 | 342 | 866 |
| | July | 573 | 376 | 949 | 488 | 286 | 774 |
| | Aug | 463 | 289 | 751 | 408 | 230 | 638 |
| | Sept | 510 | 239 | 749 | 510 | 219 | 730 |
| | Oct | 388 | 215 | 603 | 366 | 195 | 561 |
| | Nov | 339 | 185 | 524 | 334 | 176 | 510 |
| | Dec | 464 | 180 | 644 | 419 | 169 | 589 |
| **Annual aMW** | | **649** | **298** | **947** | **518** | **259** | **777** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2034 | Jan | 714 | 289 | 1,003 | 509 | 163 | 672 |
| | Feb | 849 | 328 | 1,176 | 610 | 161 | 771 |
| | Mar | 796 | 350 | 1,145 | 631 | 169 | 800 |
| | Apr | 884 | 381 | 1,265 | 831 | 335 | 1,166 |
| | May | 926 | 363 | 1,289 | 934 | 247 | 1,181 |
| | June | 881 | 381 | 1,262 | 977 | 269 | 1,245 |
| | July | 572 | 376 | 949 | 595 | 316 | 910 |
| | Aug | 462 | 289 | 751 | 504 | 350 | 853 |
| | Sept | 510 | 238 | 748 | 482 | 232 | 714 |
| | Oct | 388 | 215 | 603 | 391 | 205 | 596 |
| | Nov | 338 | 185 | 524 | 341 | 173 | 514 |
| | Dec | 463 | 180 | 644 | 415 | 169 | 584 |
| **Annual aMW** | | **649** | **298** | **947** | **601** | **232** | **834** |
| 2035 | Jan | 713 | 289 | 1,002 | 711 | 416 | 1,127 |
| | Feb | 848 | 328 | 1,176 | 806 | 399 | 1,205 |
| | Mar | 796 | 350 | 1,145 | 863 | 475 | 1,337 |
| | Apr | 884 | 381 | 1,265 | 1072 | 511 | 1,583 |
| | May | 925 | 363 | 1,289 | 1007 | 429 | 1,437 |
| | June | 881 | 381 | 1,262 | 1112 | 492 | 1,604 |
| | July | 572 | 376 | 948 | 629 | 374 | 1,003 |
| | Aug | 462 | 288 | 751 | 515 | 351 | 866 |
| | Sept | 509 | 238 | 747 | 482 | 235 | 717 |
| | Oct | 388 | 215 | 602 | 388 | 213 | 601 |
| | Nov | 338 | 185 | 523 | 346 | 174 | 519 |
| | Dec | 463 | 180 | 643 | 427 | 169 | 595 |
| **Annual aMW** | | **648** | **298** | **946** | **696** | **353** | **1,050** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2036 | Jan | 713 | 289 | 1,001 | 625 | 303 | 928 |
| | Feb | 849 | 327 | 1,176 | 696 | 300 | 996 |
| | Mar | 795 | 349 | 1,144 | 628 | 310 | 938 |
| | Apr | 884 | 381 | 1,264 | 712 | 256 | 968 |
| | May | 925 | 363 | 1,288 | 815 | 310 | 1,125 |
| | June | 880 | 381 | 1,261 | 1107 | 315 | 1,422 |
| | July | 572 | 376 | 948 | 513 | 285 | 798 |
| | Aug | 462 | 288 | 750 | 443 | 242 | 685 |
| | Sept | 508 | 238 | 747 | 494 | 229 | 723 |
| | Oct | 388 | 215 | 602 | 390 | 211 | 601 |
| | Nov | 338 | 185 | 523 | 339 | 176 | 515 |
| | Dec | 463 | 180 | 643 | 519 | 174 | 693 |
| **Annual aMW** | | **648** | **298** | **946** | **607** | **260** | **866** |
| 2037 | Jan | 710 | 288 | 999 | 822 | 269 | 1,091 |
| | Feb | 851 | 327 | 1,178 | 1053 | 303 | 1,356 |
| | Mar | 794 | 349 | 1,143 | 945 | 479 | 1,424 |
| | Apr | 883 | 381 | 1,264 | 915 | 465 | 1,380 |
| | May | 925 | 363 | 1,288 | 976 | 444 | 1,420 |
| | June | 880 | 381 | 1,261 | 1235 | 520 | 1,755 |
| | July | 571 | 376 | 947 | 1096 | 512 | 1,609 |
| | Aug | 461 | 288 | 750 | 695 | 441 | 1,136 |
| | Sept | 508 | 238 | 746 | 659 | 258 | 917 |
| | Oct | 387 | 215 | 602 | 419 | 219 | 638 |
| | Nov | 338 | 185 | 523 | 339 | 184 | 523 |
| | Dec | 463 | 180 | 643 | 618 | 444 | 1,062 |
| **Annual aMW** | | **648** | **298** | **945** | **814** | **378** | **1,193** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2038 | Jan | 709 | 288 | 997 | 1068 | 488 | 1,556 |
| | Feb | 852 | 326 | 1,178 | 1083 | 447 | 1,530 |
| | Mar | 794 | 348 | 1,142 | 939 | 441 | 1,381 |
| | Apr | 883 | 380 | 1,264 | 934 | 451 | 1,386 |
| | May | 925 | 363 | 1,288 | 676 | 379 | 1,054 |
| | June | 879 | 381 | 1,260 | 573 | 326 | 899 |
| | July | 571 | 376 | 947 | 616 | 387 | 1,003 |
| | Aug | 461 | 288 | 749 | 462 | 281 | 743 |
| | Sept | 507 | 238 | 745 | 588 | 231 | 819 |
| | Oct | 387 | 214 | 602 | 370 | 210 | 580 |
| | Nov | 338 | 185 | 523 | 327 | 181 | 508 |
| | Dec | 463 | 180 | 642 | 431 | 180 | 611 |
| **Annual aMW** | | **647** | **297** | **945** | **672** | **334** | **1,006** |
| 2039 | Jan | 708 | 287 | 995 | 478 | 182 | 660 |
| | Feb | 850 | 325 | 1,175 | 608 | 219 | 827 |
| | Mar | 793 | 348 | 1,141 | 429 | 189 | 618 |
| | Apr | 883 | 380 | 1,263 | 503 | 181 | 685 |
| | May | 924 | 363 | 1,287 | 525 | 232 | 756 |
| | June | 879 | 381 | 1,259 | 534 | 326 | 860 |
| | July | 570 | 376 | 946 | 440 | 310 | 750 |
| | Aug | 461 | 288 | 749 | 372 | 216 | 589 |
| | Sept | 507 | 238 | 745 | 432 | 210 | 643 |
| | Oct | 387 | 214 | 601 | 379 | 193 | 572 |
| | Nov | 339 | 185 | 523 | 343 | 171 | 514 |
| | Dec | 462 | 180 | 642 | 406 | 164 | 570 |
| **Annual aMW** | | **647** | **297** | **944** | **454** | **216** | **670** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2040 | Jan | 706 | 286 | 992 | 451 | 174 | 625 |
| | Feb | 849 | 325 | 1,174 | 595 | 174 | 769 |
| | Mar | 792 | 347 | 1,139 | 812 | 306 | 1,118 |
| | Apr | 883 | 385 | 1,268 | 759 | 417 | 1,176 |
| | May | 925 | 356 | 1,280 | 695 | 315 | 1,010 |
| | June | 878 | 380 | 1,258 | 622 | 297 | 919 |
| | July | 570 | 376 | 945 | 515 | 385 | 900 |
| | Aug | 460 | 288 | 748 | 436 | 282 | 718 |
| | Sept | 506 | 238 | 744 | 426 | 223 | 649 |
| | Oct | 387 | 214 | 601 | 369 | 211 | 580 |
| | Nov | 339 | 185 | 523 | 339 | 172 | 510 |
| | Dec | 462 | 180 | 642 | 499 | 174 | 672 |
| **Annual aMW** | | **646** | **297** | **943** | **543** | **261** | **804** |
| 2041 | Jan | 704 | 287 | 991 | 667 | 328 | 994 |
| | Feb | 847 | 325 | 1,173 | 943 | 360 | 1,303 |
| | Mar | 791 | 348 | 1,139 | 561 | 332 | 892 |
| | Apr | 882 | 384 | 1,267 | 518 | 298 | 816 |
| | May | 924 | 355 | 1,279 | 449 | 282 | 731 |
| | June | 877 | 380 | 1,257 | 456 | 310 | 766 |
| | July | 570 | 375 | 945 | 497 | 375 | 872 |
| | Aug | 460 | 288 | 747 | 378 | 269 | 647 |
| | Sept | 505 | 238 | 743 | 384 | 226 | 610 |
| | Oct | 386 | 214 | 601 | 358 | 200 | 558 |
| | Nov | 339 | 185 | 523 | 341 | 168 | 509 |
| | Dec | 462 | 180 | 641 | 475 | 165 | 640 |
| **Annual aMW** | | **646** | **297** | **942** | **502** | **276** | **778** |

*HCC=Hells Canyon Complex, **ROR=Run of River

| Year | Month | 50th Percentile (planning case) HCC | ROR | Total | Extreme Weather Scenario HCC | ROR | Total |
|---|---|---|---|---|---|---|---|
| 2042 | Jan | 701 | 286 | 987 | 547 | 196 | 743 |
| | Feb | 846 | 324 | 1,171 | 697 | 206 | 903 |
| | Mar | 790 | 347 | 1,137 | 746 | 174 | 919 |
| | Apr | 882 | 383 | 1,265 | 932 | 243 | 1,175 |
| | May | 924 | 354 | 1,278 | 818 | 245 | 1,064 |
| | June | 877 | 380 | 1,256 | 575 | 244 | 819 |
| | July | 569 | 375 | 945 | 508 | 355 | 862 |
| | Aug | 459 | 288 | 747 | 400 | 242 | 642 |
| | Sept | 504 | 237 | 742 | 440 | 218 | 658 |
| | Oct | 386 | 214 | 600 | 371 | 190 | 561 |
| | Nov | 339 | 185 | 523 | 342 | 156 | 498 |
| | Dec | 461 | 179 | 641 | 437 | 158 | 595 |
| **Annual aMW** | | **645** | **296** | **941** | **568** | **219** | **787** |
| 2043 | Jan | 701 | 268 | 969 | 734 | 226 | 960 |
| | Feb | 846 | 306 | 1,153 | 1098 | 406 | 1,504 |
| | Mar | 790 | 329 | 1,119 | 946 | 509 | 1,454 |
| | Apr | 882 | 366 | 1,248 | 952 | 499 | 1,450 |
| | May | 924 | 335 | 1,259 | 1089 | 514 | 1,603 |
| | June | 877 | 360 | 1,237 | 1187 | 456 | 1,643 |
| | July | 569 | 356 | 925 | 650 | 343 | 992 |
| | Aug | 459 | 269 | 728 | 553 | 360 | 913 |
| | Sept | 504 | 217 | 721 | 620 | 236 | 857 |
| | Oct | 386 | 195 | 581 | 407 | 212 | 618 |
| | Nov | 339 | 168 | 506 | 329 | 175 | 503 |
| | Dec | 461 | 162 | 623 | 454 | 196 | 650 |
| **Annual aMW** | | **645** | **278** | **922** | **751** | **344** | **1,096** |

*HCC=Hells Canyon Complex, **ROR=Run of River

# LONG-TERM CAPACITY EXPANSION RESULTS (MW)

## Main Cases

### *Preferred Portfolio–Valmy 1 & 2 (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 100 | 500 | 155 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 400 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 100 | 205 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 50 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 155 | 50 | 200 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 967 | 340 | 1,800 | 3,325 | 1,103 | 150 | 200 | | 30 | 160 | 360 |
| **Total** | **6,888** | **Portfolio Cost: $9,746M** | | | | | | | | | | | |

## *Valmy 2 (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 55 | 150 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 300 | 5 | 0 | 0 | 0 | 30 | 20 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 100 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 600 | 105 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 40 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 205 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 |
| 2038 | 0 | -706 | 340 | 340 | 0 | 0 | 55 | 50 | 50 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,180 | 340 | 1,800 | 2,625 | 1,053 | 200 | 100 | | 30 | 140 | 360 |
| **Total** | **6,281** | **Portfolio Cost: $9,795M** | | | | | | | | | | | |

### *Without Valmy (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | Jul B2H | 20 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 40 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 155 | 0 | 0 | 0 | 40 | 21 |
| 2029 | 0 | 0 | 170 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 200 | 400 | 5 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 400 | 205 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 205 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 20 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 100 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 50 | 200 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | GWW3 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,046 | 340 | 1,800 | 3,425 | 1,053 | 200 | 200 | | 160 | 360 |
| **Total** | **7,037** | **Portfolio Cost: $9,824M** | | | | | | | | | | |

## November 2026 B2H Valmy 1 & 2 (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 400 | 155 | 0 | 0 | Nov B2H | 40 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 100 | 150 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 500 | 55 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 0 | 5 | 0 | 0 | 0 | 20 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 40 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 40 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 55 | 0 | 200 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 20 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | GWW3 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 300 | 55 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,137 | 340 | 1,800 | 2,825 | 908 | 150 | 200 | | 180 | 360 |
| **Total** | **6,353** | **Portfolio Cost: $9,767M** | | | | | | | | | | |

## *November 2026 B2H Valmy 2 (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 400 | 205 | 100 | 0 | Nov B2H | 20 | 19 | 0 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 100 | 150 | 5 | 0 | 0 | 0 | 0 | 21 | 0 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 100 | 5 | 0 | 0 | GWW1 | 20 | 22 | 0 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 20 | 21 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | GWW2 | 0 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 0 | 5 | 0 | 50 | 0 | 0 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 20 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 50 | 0 | 0 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 17 | 0 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 200 | 705 | 0 | 50 | 0 | 0 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 20 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | GWW3 | 20 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 14 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 400 | 55 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 14 | 0 |
| Subtotal | -841 | -706 | 1,010 | 340 | 1,800 | 3,325 | 1,413 | 100 | 200 | | 160 | 360 | 14 |
| **Total** | **7,175** | **Portfolio Cost: $9,880M** | | | | | | | | | | | |

## *November 2026 B2H Without Valmy (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 0 | 0 | 0 | 400 | 100 | 300 | 0 | Nov B2H | 0 | 40 | 19 | 27 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 100 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 21 | 0 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 | 0 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 0 | 0 | 0 | 0 | 30 | 0 | 21 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 100 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 400 | 205 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 40 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 | 0 |
| 2037 | 0 | 0 | 340 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 5 | 0 | 100 | 0 | 0 | 0 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | GWW3 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| Subtotal | -841 | -706 | 1,046 | 340 | 1,800 | 3,325 | 833 | 300 | 150 | | 30 | 180 | 360 | 27 |
| **Total** | **6,844** | **Portfolio Cost: $10,192M** | | | | | | | | | | | | |

## *Without GWW Segments (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | Pumped Storage | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 100 | 375 | 0 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 | 0 | 40 | 21 |
| 2029 | 0 | 0 | 300 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 | 40 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 200 | 0 | 0 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 100 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 200 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 170 | 0 | 100 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 200 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,737 | 340 | 900 | 825 | 478 | 250 | 50 | | 60 | 100 | 360 |
| **Total** | **3,553** | **Portfolio Cost: $10,326M** | | | | | | | | | | | |

## GWW Segment 1 Only (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | Pumped Storage | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 400 | 0 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 200 | 675 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 0 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 170 | 0 | 0 | 200 | 155 | 0 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 200 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 30 | 20 | 20 |
| 2033 | 0 | 0 | 300 | 0 | 200 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 170 | 0 | 0 | 5 | 300 | 0 | 100 | 0 | 0 | 60 | 17 |
| 2039 | 0 | 0 | 0 | 170 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,437 | 340 | 1,000 | 1,725 | 533 | 300 | 250 | 200 | | 30 | 140 | 360 |
| **Total** | **4,768** | **Portfolio Cost: $10,263M** | | | | | | | | | | | | |

## *GWW Segments 1 & 2 Only (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 5 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 105 | 0 | GWW1 | 0 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 200 | 400 | 55 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 0 | 5 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 300 | 305 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 300 | 150 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 50 | 50 | 0 | 0 | 40 | 17 |
| 2038 | 0 | -706 | 340 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 30 | 0 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,800 | 1,925 | 1,033 | 150 | | 30 | 140 | 360 |
| **Total** | **5,538** | **Portfolio Cost: $9,759M** | | | | | | | | | | |

## Scenarios and Sensitivities

### *High Gas High Carbon (MW)*

| Year | Coal Exits | Gas Exits | New Gas | Wind | Solar | 4-Hr | 8-Hr | Pumped Storage | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 134 | 0 | 100 | 0 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 | 0 |
| 2027 | 0 | 0 | 0 | 400 | 375 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 21 | 9 |
| 2029 | 0 | 0 | 170 | 400 | 100 | 5 | 50 | 0 | 0 | GWW1 | 0 | 0 | 22 | 9 |
| 2030 | -350 | -134 | 820 | 200 | 0 | 5 | 50 | 0 | 0 | 0 | 30 | 0 | 21 | 11 |
| 2031 | 0 | 0 | 0 | 400 | 600 | 5 | 200 | 250 | 0 | GWW2 | 30 | 40 | 21 | 12 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 200 | 50 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 17 | 0 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 | 0 | 20 | 17 | 0 |
| 2038 | 0 | -706 | 0 | 0 | 0 | 355 | 0 | 0 | 50 | 0 | 0 | 20 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 40 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 40 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | GWW3 | 0 | 0 | 14 | 0 |
| Subtotal | -841 | -840 | 1,480 | 1,800 | 2,525 | 913 | 300 | 250 | 100 | | 60 | 180 | 360 | 41 |
| **Total** | **6,328** | **Portfolio Cost: $12,520M** | | | | | | | | | | | | |

## *Low Gas Zero Carbon (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 0 | 0 | 0 | Jul B2H | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 200 | 150 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 300 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 200 | 155 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 400 | 155 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 200 | 155 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 340 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 5 | 0 | 100 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | GWW3 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 5 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,800 | 3,425 | 903 | 50 | 100 | | 140 | 360 |
| **Total** | **6,878** | **Portfolio Cost: $8,594M** | | | | | | | | | | |

## *Constrained Storage (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 0 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 | 0 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 20 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 40 | 21 | 0 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 400 | 55 | 0 | 0 | GWW1 | 0 | 40 | 22 | 0 |
| 2030 | -350 | 0 | 350 | 0 | 200 | 0 | 5 | 200 | 0 | 0 | 0 | 0 | 21 | 0 |
| 2031 | 0 | -134 | 0 | 0 | 400 | 500 | 5 | 100 | 0 | GWW2 | 30 | 20 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | 30 | 20 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 100 | 0 | 0 | 30 | 0 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 30 | 0 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 20 | 14 | 14 |
| Subtotal | -841 | -840 | 1,180 | 340 | 1,800 | 2,425 | 458 | 550 | 150 | | 120 | 160 | 360 | 14 |
| **Total** | **5,876** | **Portfolio Cost: $10,007M** | | | | | | | | | | | | |

## *100% Clean by 2045 (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 100 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2029 | -175 | 0 | 340 | 0 | 400 | 0 | 305 | 0 | 0 | GWW1 | 0 | 40 | 22 |
| 2030 | -174 | 0 | 0 | 0 | 400 | 200 | 205 | 0 | 50 | 0 | 30 | 40 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 200 | 100 | 5 | 0 | 0 | GWW2 | 0 | 20 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 50 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 100 | 0 | 0 | 0 | 19 |
| 2035 | 0 | -134 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -357 | 0 | 170 | 0 | 0 | 5 | 100 | 50 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 100 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 0 | 50 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -491 | 831 | 340 | 1,800 | 2,725 | 993 | 250 | 200 | | 30 | 160 | 360 |
| **Total** | **6,357** | **Portfolio Cost: $9,808M** | | | | | | | | | | | |

## *Additional Large Load 100 MW (MW)*

| Year | Coal Exits | Gas | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 40 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 55 | 50 | 0 | GWW1 | 0 | 40 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 300 | 105 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 0 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 600 | 155 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 205 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 100 | 155 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 170 | 170 | 0 | 0 | 5 | 100 | 200 | 0 | 0 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,137 | 340 | 1,800 | 3,325 | 1,213 | 200 | 200 | | 30 | 160 | 360 |
| **Total** | **7,218** | **Portfolio Cost: $10,236M** | | | | | | | | | | | |

## *Additional Large Load 200 MW (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 20 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 100 | 0 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 300 | 255 | 0 | 0 | GWW1 | 0 | 40 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 0 | 205 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 500 | 5 | 0 | 0 | GWW2 | 30 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 30 | 40 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 100 | 0 | 0 | 0 | 20 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 0 | 150 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 100 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 200 | 100 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,800 | 2,725 | 998 | 250 | 200 | | 90 | 180 | 360 |
| **Total** | **6,703** | **Portfolio Cost: $10,747** | | | | | | | | | | | |

### 100% Clean by 2035 (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | Pumped Storage | 100-Hr | Trans. | Geo | Biomass | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 100 | 105 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 0 | 19 | 0 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 21 | 0 |
| 2029 | -175 | 0 | 0 | 0 | 400 | 0 | 5 | 250 | 0 | 0 | GWW1 | 0 | 0 | 40 | 22 | 0 |
| 2030 | -174 | 0 | 0 | 0 | 400 | 200 | 105 | 0 | 0 | 50 | 0 | 30 | 30 | 20 | 21 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 200 | 500 | 5 | 50 | 0 | 0 | GWW2 | 30 | 0 | 0 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 200 | 105 | 50 | 0 | 50 | 0 | 30 | 30 | 0 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 100 | 205 | 0 | 0 | 0 | 0 | 30 | 30 | 0 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 100 | 0 | 50 | 0 | 0 | 30 | 40 | 19 | 0 |
| 2035 | 0 | -1,260 | 0 | 0 | 0 | 0 | 5 | 150 | 500 | 50 | 0 | 30 | 30 | 60 | 18 | 43 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | 0 | 0 | 170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | GWW3 | 0 | 0 | 0 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 42 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 250 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 41 |
| Subtotal | -841 | -1,260 | 491 | 340 | 1,800 | 2,125 | 1,053 | 850 | 500 | 200 | | 150 | 150 | 180 | 360 | 127 |
| **Total** | **7,168** | **Portfolio Cost: $11,351M** | | | | | | | | | | | | | | |

## *New Forecasted PURPA (MW)*

| Year | Coal Exits | Gas Exits | New Gas | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Hydro | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 100 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 400 | 775 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 23 | 182 | 5 | 0 | 0 | 0 | 2 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 423 | 32 | 5 | 0 | 0 | GWW1 | 2 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 423 | 232 | 5 | 0 | 0 | 0 | 2 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 423 | 32 | 55 | 100 | 0 | GWW2 | 2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 223 | 432 | 5 | 0 | 0 | 0 | 2 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 23 | 32 | 55 | 0 | 0 | 0 | 2 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 20 | 18 |
| 2036 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 40 | 17 |
| 2038 | 0 | -706 | 0 | 23 | 32 | 505 | 200 | 150 | 0 | 2 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 20 | 15 |
| 2040 | 0 | 0 | 0 | 23 | 32 | 0 | 0 | 0 | 0 | 2 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 23 | 32 | 5 | 0 | 0 | 0 | 2 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 23 | 132 | 5 | 0 | 0 | GWW3 | 2 | 0 | 14 |
| Subtotal | -841 | -706 | 967 | 2,168 | 2,537 | 1,003 | 300 | 150 | | 32 | 160 | 360 |
| **Total** | **6,130** | **Portfolio Cost: $10,720M** | | | | | | | | | | 0 |

## *Extreme Weather (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 5 | 100 | 0 | Jul B2H | 20 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 40 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 55 | 50 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 170 | 0 | 400 | 0 | 0 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 300 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 0 | 5 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 400 | 205 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 50 | 0 | 0 | 20 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 0 | 200 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | GWW3 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 100 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,800 | 2,625 | 858 | 300 | 200 | | 180 | 360 |
| **Total** | **6,423** | **Portfolio Cost: $10,211M** | | | | | | | | | | |

## *Rapid Electrification Air-Source Heat Pump (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 5 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 50 | 0 | 0 | 0 | 20 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 200 | 0 | 0 | 0 | 40 | 21 |
| 2029 | 0 | 0 | 300 | 0 | 400 | 300 | 5 | 0 | 0 | GWW1 | 0 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 0 | 5 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | 0 | 170 | 0 | 300 | 400 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 300 | 355 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 705 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 340 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 20 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 340 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 0 | 150 | 0 | 30 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 150 | 0 | 0 | 20 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 0 | 0 | 200 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 400 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 100 | 50 | 0 | 0 | 20 | 14 |
| Subtotal | -841 | -706 | 2,287 | 340 | 1,800 | 3,425 | 1,453 | 350 | 600 | | 60 | 160 | 360 |
| **Total** | **9,288** | **Portfolio Cost: $12,271M** | | | | | | | | | | | |

## *Rapid Electrification Ground-Source Heat Pump (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 300 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 200 | 400 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 170 | 0 | 0 | 300 | 5 | 50 | 0 | 0 | 20 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 250 | 0 | 0 | 20 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 340 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 |
| 2038 | 0 | -706 | 340 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 15 |
| 2040 | 0 | 0 | 0 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | GWW3 | 20 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 50 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 2,287 | 340 | 1,800 | 2,125 | 413 | 300 | 50 | | 180 | 360 |
| **Total** | **6,308** | **Portfolio Cost: $11,175M** | | | | | | | | | | |

## Load Flattening (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 5 | 0 | 0 | Jul B2H | 0 | 20 | 19 | 0 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 | 20 | 0 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 55 | 50 | 0 | 0 | 0 | 40 | 21 | 0 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 255 | 0 | 0 | GWW1 | 0 | 0 | 22 | 0 |
| 2030 | -350 | 0 | 350 | 0 | 300 | 300 | 205 | 0 | 0 | 0 | 30 | 0 | 21 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 600 | 205 | 0 | 0 | GWW2 | 30 | 0 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 100 | 55 | 0 | 0 | 0 | 0 | 20 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 17 | 0 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 0 | 150 | 0 | 0 | 0 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 0 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 20 | 14 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,800 | 3,325 | 1,163 | 50 | 200 | | 60 | 180 | 360 | 14 |
| **Total** | **7,252** | **Portfolio Cost: $10,663M** | | | | | | | | | | | | |

## Validation and Verification

### *Valmy 1 & 2 Early Exit (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 100 | 0 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 100 | 500 | 155 | 0 | 0 | 0 | 30 | 0 | 21 |
| 2031 | 0 | -127 | 0 | 0 | 400 | 400 | 155 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | -134 | 170 | 0 | 100 | 100 | 205 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 50 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 50 | 200 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -967 | 1,307 | 340 | 1,800 | 3,325 | 1,103 | 150 | 200 | | 30 | 160 | 360 |
| **Total** | **6,967** | **Portfolio Cost: $9,803M** | | | | | | | | | | | |

## Valmy 2 Early Exit (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 100 | 5 | 0 | 0 | Jul B2H | 0 | 40 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 400 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | -134 | 170 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 50 | 0 | 0 | 20 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 100 | 0 | 5 | 0 | 0 | GWW2 | 0 | 20 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 100 | 0 | 0 | 30 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 100 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 100 | 600 | 205 | 0 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 400 | 205 | 0 | 0 | 0 | 0 | 20 | 18 |
| 2036 | 0 | 0 | 170 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 170 | 0 | 0 | 5 | 0 | 100 | 0 | 0 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 300 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -840 | 1,180 | 340 | 1,800 | 2,725 | 1,058 | 200 | 200 | | 30 | 180 | 360 |
| **Total** | **6,392** | **Portfolio Cost: $9,878M** | | | | | | | | | | | |

## *November 2026 B2H Valmy 1 & 2 Early Exit (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 200 | 205 | 0 | 0 | Nov B2H | 0 | 20 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 300 | 150 | 5 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | -127 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 40 | 22 |
| 2030 | -350 | -134 | 520 | 0 | 400 | 0 | 55 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 0 | 155 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 600 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 50 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 20 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 50 | 0 | 0 | 0 | 40 | 17 |
| 2038 | 0 | -706 | 170 | 340 | 0 | 0 | 5 | 50 | 200 | 0 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 20 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 300 | 0 | 50 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -967 | 1,307 | 340 | 1,800 | 3,325 | 898 | 250 | 200 | | 0 | 160 | 360 |
| **Total** | **6,832** | **Portfolio Cost: $9,880M** | | | | | | | | | | | |

## *November 2026 B2H Valmy 2 Early Exit (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 134 | 0 | 0 | 400 | 205 | 100 | 0 | Nov B2H | 20 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 100 | 150 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | -134 | 170 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 100 | 5 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 400 | 0 | 0 | 50 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 105 | 0 | 0 | 0 | 20 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 405 | 0 | 100 | 0 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | GWW3 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 55 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 20 | 14 |
| Subtotal | -841 | -840 | 1,180 | 340 | 1,800 | 3,425 | 1,248 | 100 | 200 | | 140 | 360 |
| **Total** | **7,112** | **Portfolio Cost: $9,956M** | | | | | | | | | | |

## *Without Bridger 3 & 4 (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Geo | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 575 | 5 | 0 | 0 | 0 | 0 | 20 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 300 | 150 | 5 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 170 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 0 | 0 | 400 | 200 | 105 | 0 | 50 | 0 | 30 | 40 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 300 | 100 | 155 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 600 | 205 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 17 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 50 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -357 | 170 | 170 | 0 | 0 | 5 | 150 | 0 | 0 | 0 | 0 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | GWW3 | 0 | 0 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 20 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 500 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -357 | 958 | 170 | 1,800 | 3,425 | 1,163 | 150 | 100 | | 30 | 160 | 360 |
| **Total** | **7,468** | **Portfolio Cost: $9,945M** | | | | | | | | | | | |

## Nuclear (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Nuclear | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 300 | 5 | 0 | 0 | Jul B2H | 0 | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 200 | 150 | 5 | 0 | 0 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 0 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW2 | 0 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 0 | 205 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 400 | 205 | 0 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 17 |
| 2037 | 0 | 0 | 170 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 100 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 5 | 200 | 50 | 0 | 0 | 40 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 40 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | GWW3 | 0 | 20 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 300 | 55 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 400 | 50 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,137 | 340 | 1,800 | 3,025 | 1,053 | 200 | 50 | | 100 | 160 | 360 |
| **Total** | **6,678** | **Portfolio Cost: $10,013M** | | | | | | | | | | | |

## *Wind +30% Cost (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 475 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 200 | 350 | 5 | 0 | 0 | 0 | 0 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 400 | 55 | 0 | 0 | GWW1 | 20 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 100 | 100 | 155 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 200 | 600 | 155 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 100 | 100 | 205 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 155 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 |
| 2037 | 0 | 0 | 340 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 5 | 100 | 50 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | GWW3 | 20 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 100 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 100 | 0 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 1,307 | 340 | 1,600 | 3,225 | 1,253 | 100 | 50 | | 100 | 360 |
| **Total** | **6,788** | **Portfolio Cost: $10,397M** | | | | | | | | | | |

## Energy Efficiency (MW)

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast | Energy Efficiency Bundles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 0 | 5 | 0 | 0 | Jul B2H | 0 | 19 | 27 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 675 | 5 | 0 | 0 | 0 | 0 | 20 | 33 |
| 2028 | 0 | 0 | 0 | 0 | 200 | 150 | 5 | 0 | 0 | 0 | 20 | 21 | 38 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 200 | 5 | 0 | 0 | GWW1 | 20 | 22 | 0 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 0 | 5 | 0 | 0 | 0 | 0 | 21 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 100 | 205 | 0 | 0 | GWW2 | 0 | 21 | 0 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 100 | 205 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 400 | 205 | 0 | 0 | 0 | 0 | 20 | 0 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 19 | 0 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 0 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 | 0 |
| 2037 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 17 | 0 |
| 2038 | 0 | -706 | 0 | 340 | 0 | 0 | 5 | 50 | 200 | 0 | 40 | 17 | 0 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 15 | 0 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 300 | 5 | 0 | 0 | GWW3 | 20 | 14 | 0 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 50 | 0 | 0 | 14 | 0 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 100 | 5 | 0 | 0 | 0 | 0 | 14 | 0 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 0 | 14 | 0 |
| Subtotal | -841 | -706 | 967 | 340 | 1,800 | 2,625 | 1,048 | 50 | 250 | | 160 | 360 | 98 |
| **Total** | **6,151** | **Portfolio Cost: $10,042M** | | | | | | | | | | | |

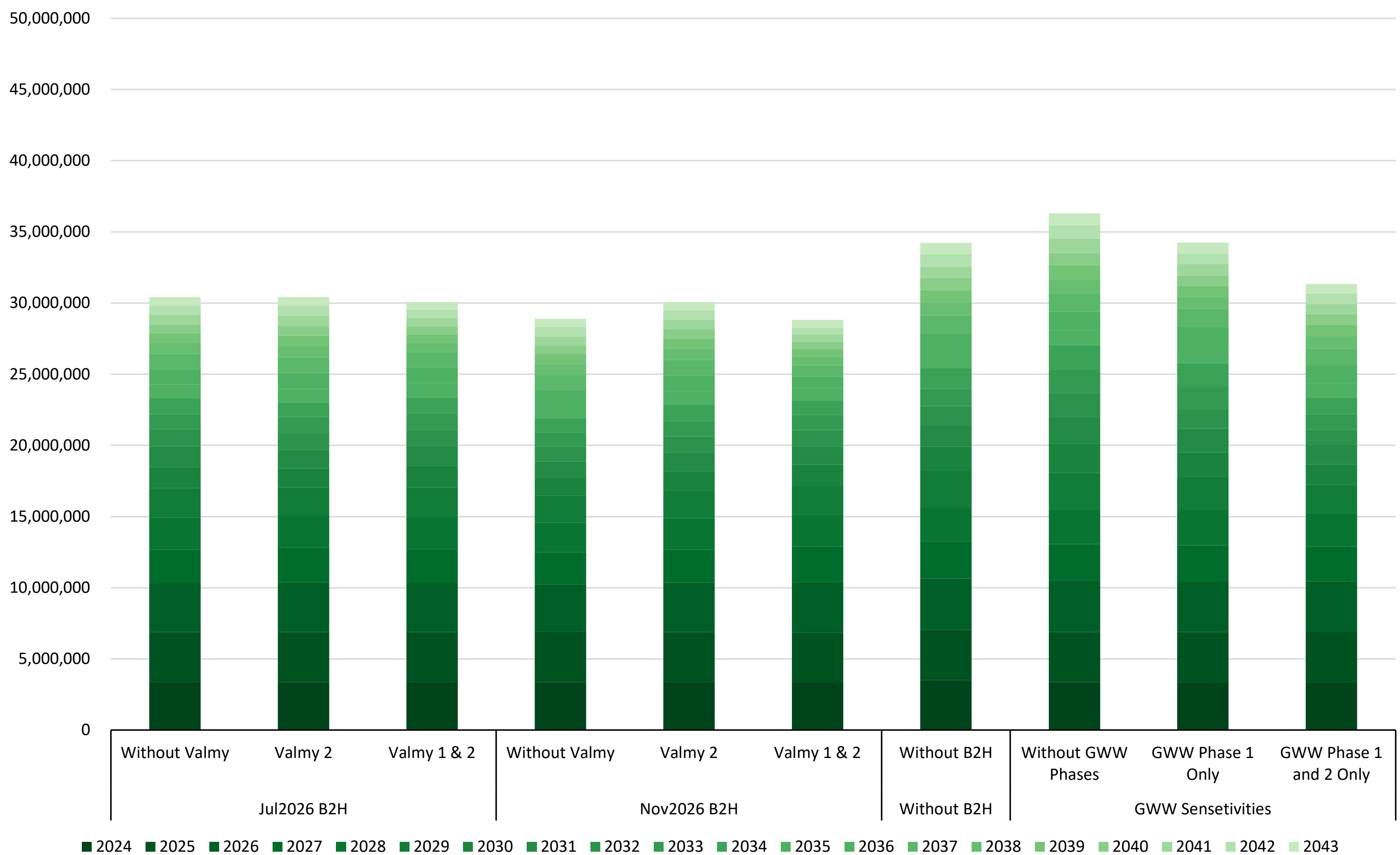
## *Demand Response (MW)*

| Year | Coal Exits | Gas Exits | New Gas | H2 | Wind | Solar | 4-Hr | 8-Hr | 100-Hr | Trans. | Demand Response | Energy Efficiency Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | -357 | 0 | 357 | 0 | 0 | 100 | 96 | 0 | 0 | 0 | 0 | 17 |
| 2025 | 0 | 0 | 0 | 0 | 0 | 200 | 227 | 0 | 0 | 0 | 0 | 18 |
| 2026 | -134 | 0 | 261 | 0 | 0 | 300 | 0 | 0 | 0 | Jul B2H | 40 | 19 |
| 2027 | 0 | 0 | 0 | 0 | 400 | 375 | 5 | 0 | 0 | 0 | 0 | 20 |
| 2028 | 0 | 0 | 0 | 0 | 200 | 150 | 5 | 0 | 0 | 0 | 20 | 21 |
| 2029 | 0 | 0 | 0 | 0 | 400 | 0 | 5 | 0 | 0 | GWW1 | 0 | 22 |
| 2030 | -350 | 0 | 350 | 0 | 400 | 200 | 105 | 0 | 0 | 0 | 0 | 21 |
| 2031 | 0 | 0 | 0 | 0 | 400 | 400 | 205 | 0 | 0 | GWW2 | 0 | 21 |
| 2032 | 0 | 0 | 0 | 0 | 0 | 0 | 205 | 0 | 0 | 0 | 0 | 20 |
| 2033 | 0 | 0 | 0 | 0 | 0 | 200 | 155 | 0 | 0 | 0 | 0 | 20 |
| 2034 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 19 |
| 2035 | 0 | 0 | 0 | 0 | 0 | 0 | 55 | 0 | 0 | 0 | 0 | 18 |
| 2036 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 17 |
| 2037 | 0 | 0 | 0 | 170 | 0 | 0 | 5 | 0 | 0 | 0 | 20 | 17 |
| 2038 | 0 | -706 | 0 | 170 | 0 | 0 | 55 | 100 | 200 | 0 | 20 | 17 |
| 2039 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 40 | 15 |
| 2040 | 0 | 0 | 0 | 0 | 0 | 400 | 0 | 0 | 0 | GWW3 | 20 | 14 |
| 2041 | 0 | 0 | 0 | 0 | 0 | 200 | 5 | 0 | 0 | 0 | 20 | 14 |
| 2042 | 0 | 0 | 0 | 0 | 0 | 400 | 5 | 0 | 0 | 0 | 0 | 14 |
| 2043 | 0 | 0 | 0 | 0 | 0 | 100 | 0 | 50 | 0 | 0 | 0 | 14 |
| Subtotal | -841 | -706 | 967 | 340 | 1,800 | 3,025 | 1,148 | 150 | 200 | | 180 | 360 |
| **Total** | **6,623** | **Portfolio Cost: $9,816M** | | | | | | | | | | |

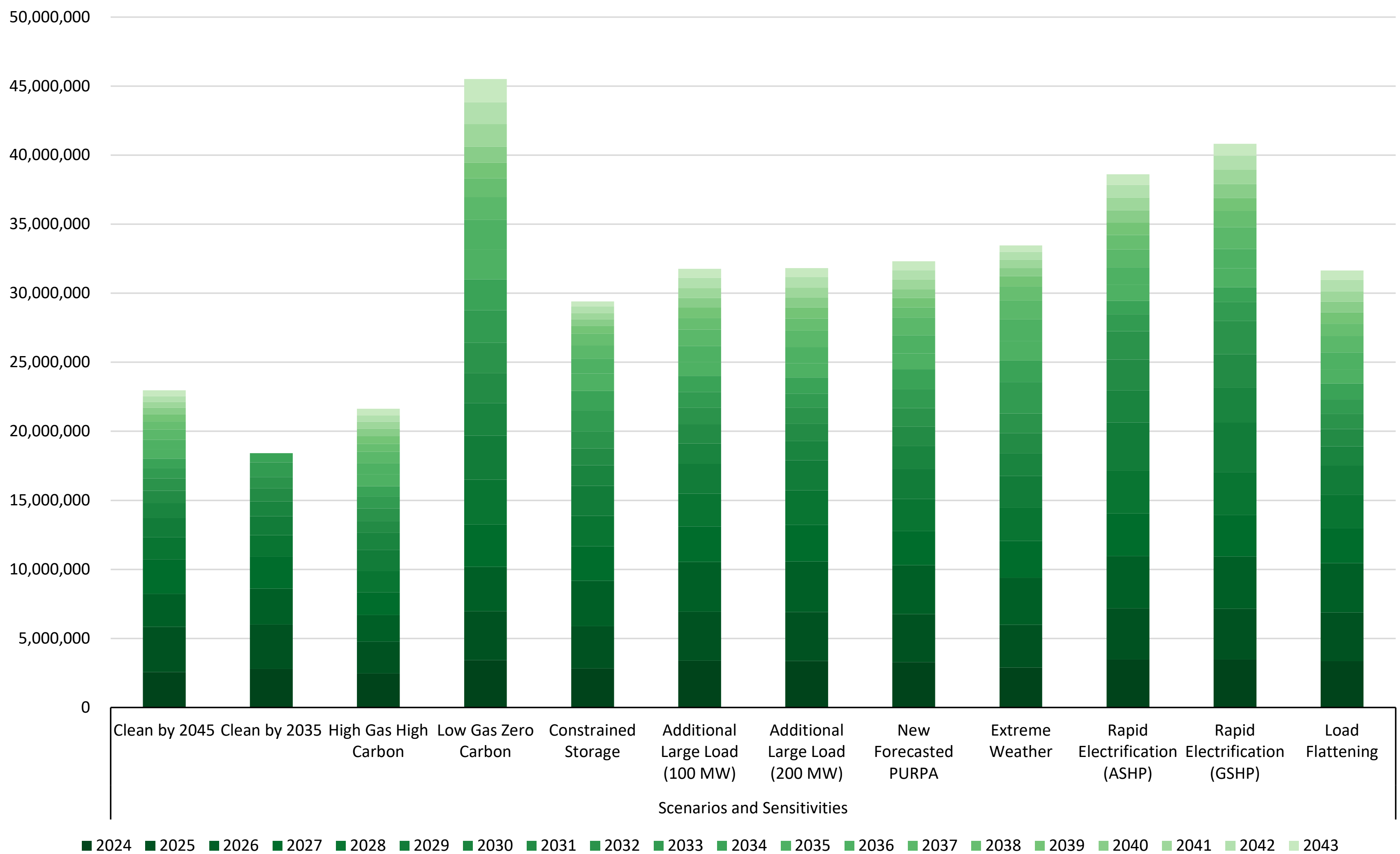
# PORTFOLIO EMISSIONS FORECAST

Total emissions forecasts for Idaho Power's resources are outputs of the AURORA model and are presented below.

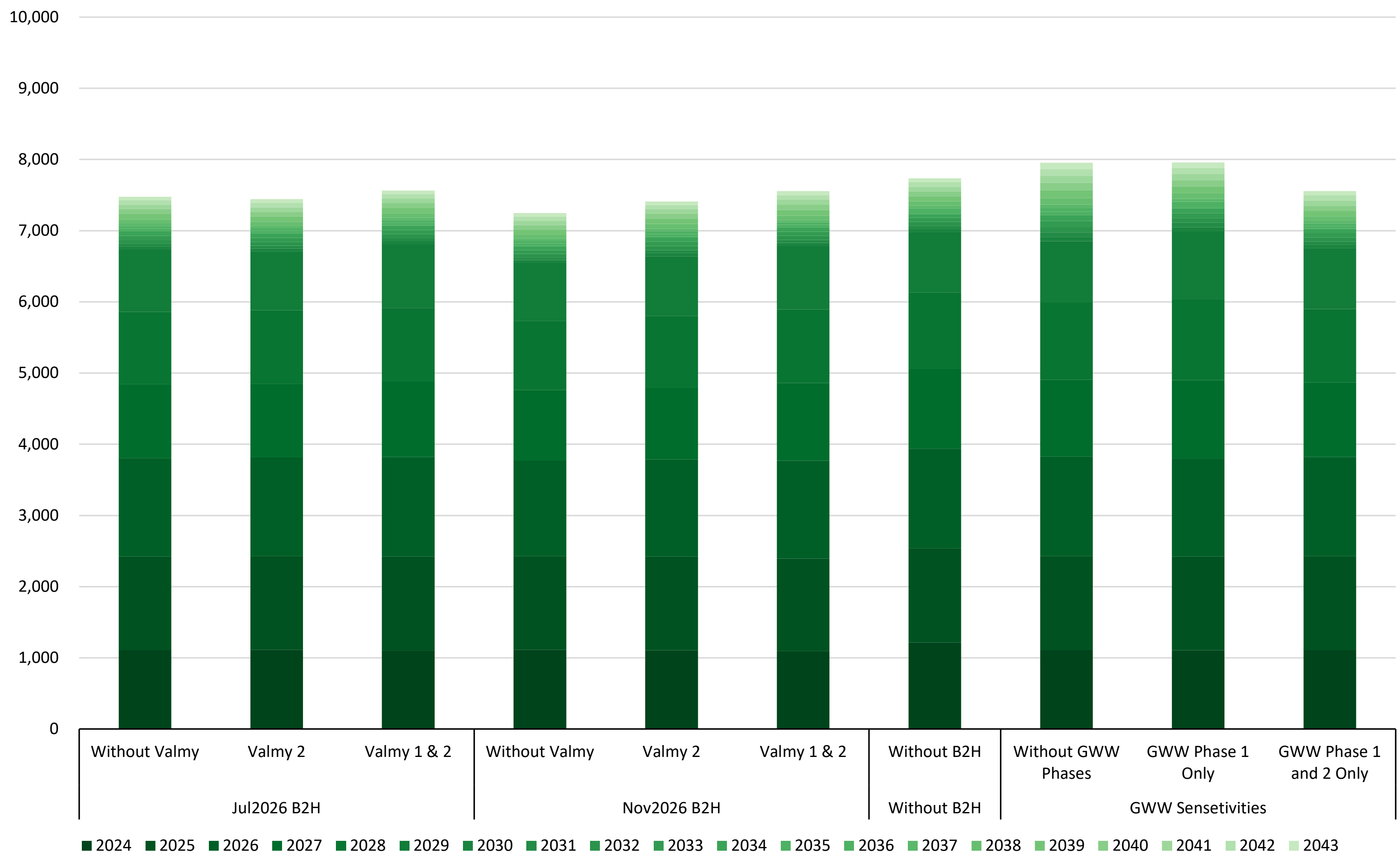
## Main Cases $CO_2$ Emissions (Metric Tons)



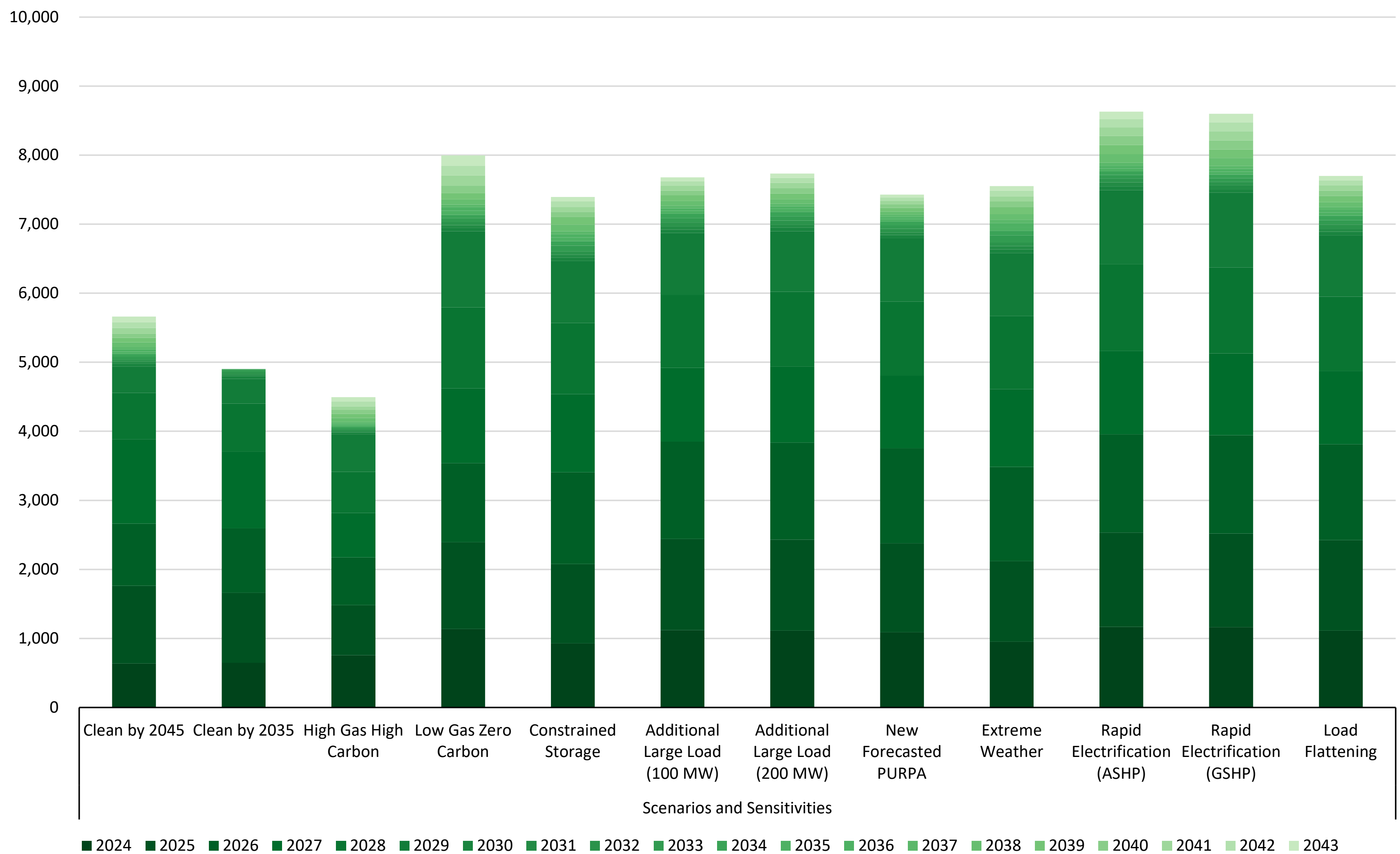
## Scenarios and Sensitivities $CO_2$ Emissions (Metric Tons):



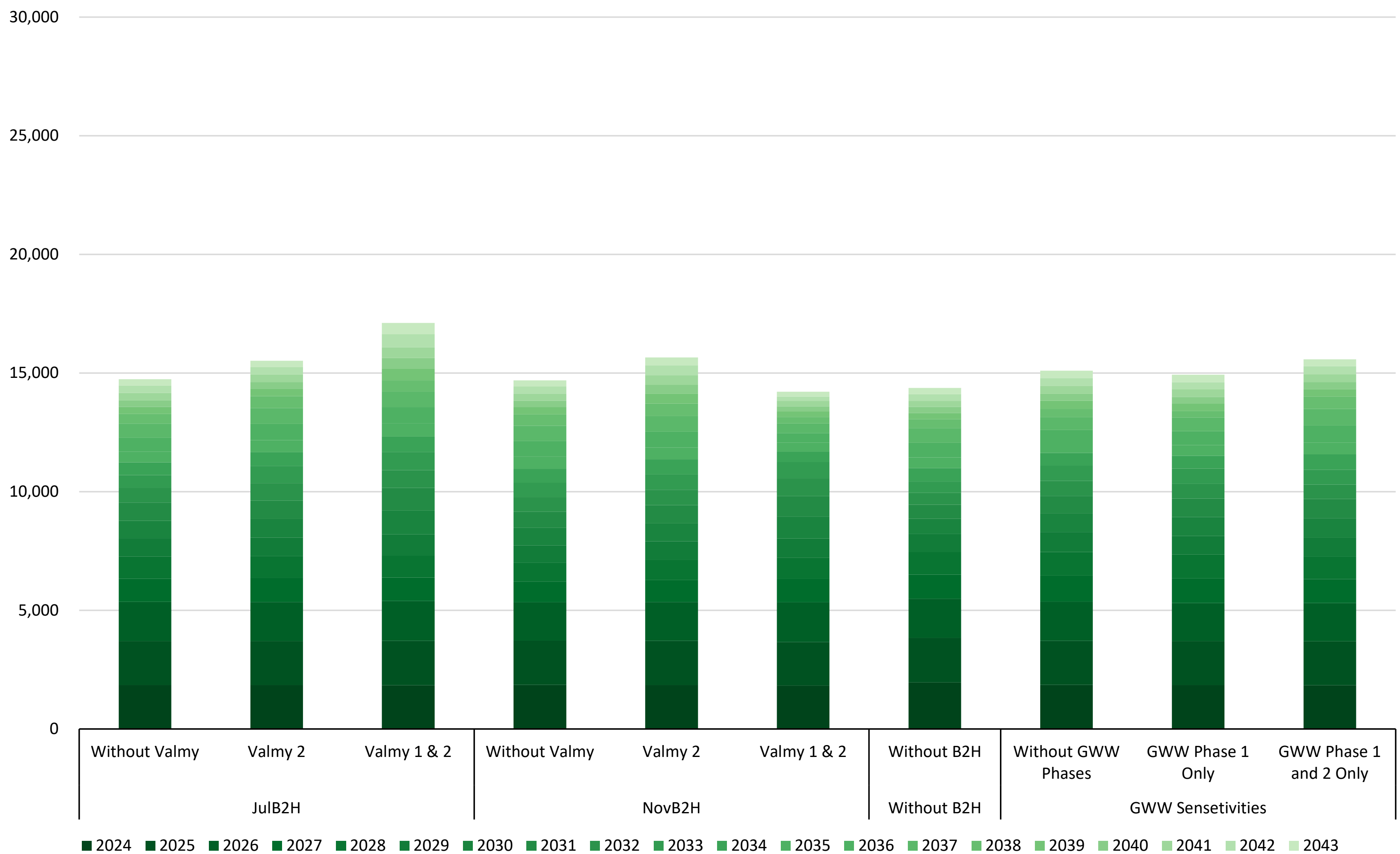
## Main Cases $SO_2$ Emissions (Metric Tons)



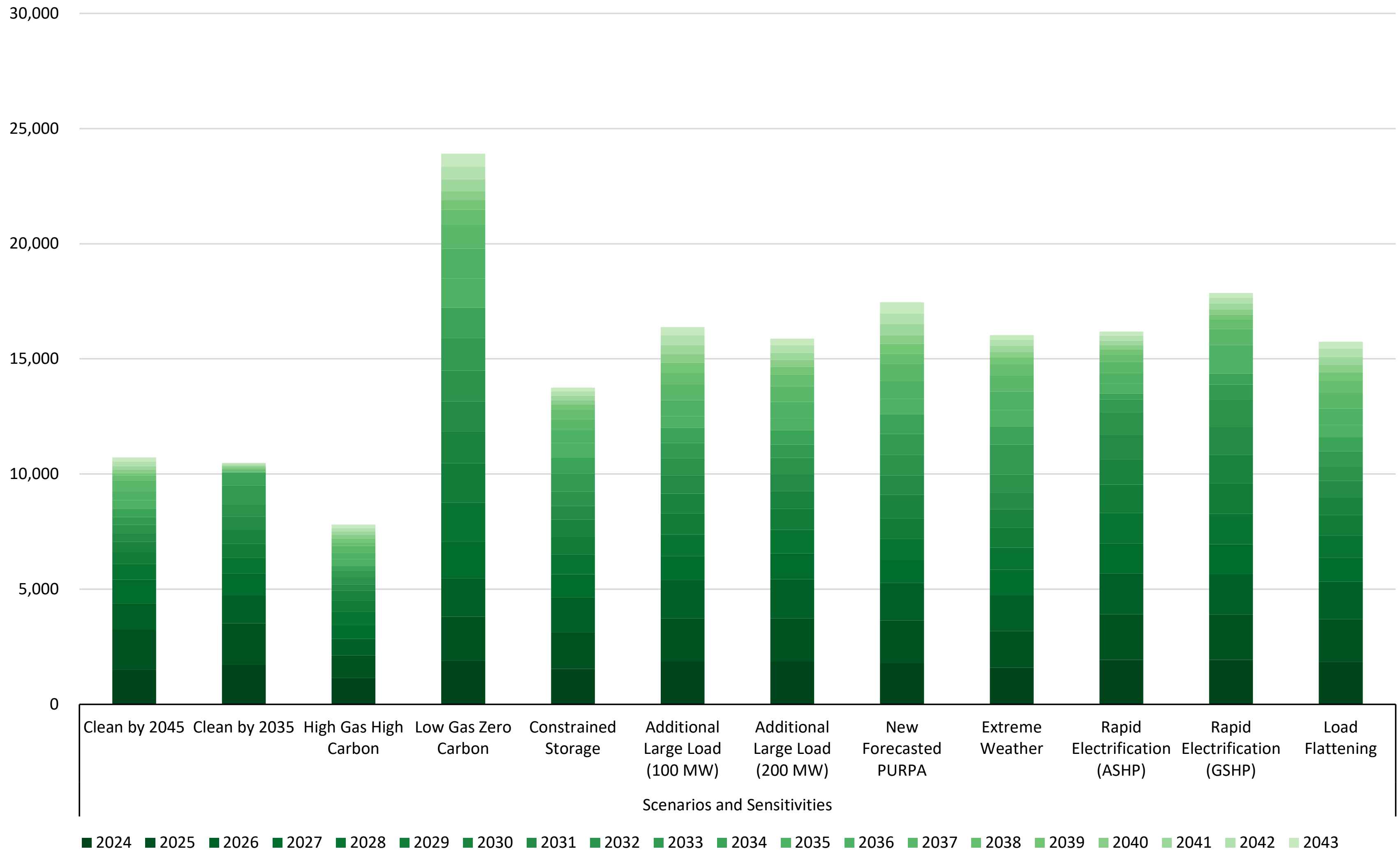
## Scenarios and Sensitivities $SO_2$ Emissions (Metric Tons)



## Main Cases NOx Emissions (Metric Tons)



## Scenarios and Sensitivities NOx Emissions (Metric Tons)



## Portfolio Emissions

### *Main Cases $CO_2$ Emissions (Metric Tons)*

| | Jul 2026 B2H | | | Nov 2026 B2H | | | Without B2H | GWW Sensitivities | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without B2H | Without GWW Phases | GWW Phase 1 Only | GWW Phase 1 & 2 Only |
| 2024 | 3,366,607 | 3,367,669 | 3,357,617 | 3,379,473 | 3,363,060 | 3,320,049 | 3,505,699 | 3,372,487 | 3,363,600 | 3,361,768 |
| 2025 | 3,521,270 | 3,524,571 | 3,536,838 | 3,529,678 | 3,535,784 | 3,511,761 | 3,545,252 | 3,525,218 | 3,527,529 | 3,518,734 |
| 2026 | 3,421,105 | 3,486,914 | 3,421,537 | 3,335,433 | 3,467,332 | 3,565,157 | 3,587,283 | 3,611,925 | 3,531,603 | 3,564,589 |
| 2027 | 2,364,726 | 2,423,051 | 2,372,879 | 2,243,730 | 2,311,886 | 2,498,553 | 2,600,665 | 2,560,169 | 2,569,174 | 2,449,896 |
| 2028 | 2,244,285 | 2,281,218 | 2,278,820 | 2,096,509 | 2,215,993 | 2,217,390 | 2,425,029 | 2,439,040 | 2,524,128 | 2,330,484 |
| 2029 | 2,085,818 | 1,961,086 | 2,076,325 | 1,887,008 | 1,936,454 | 2,066,820 | 2,536,951 | 2,561,134 | 2,243,672 | 2,007,467 |
| 2030 | 1,477,117 | 1,340,036 | 1,496,445 | 1,267,148 | 1,331,183 | 1,462,190 | 1,702,552 | 2,041,235 | 1,751,621 | 1,443,322 |
| 2031 | 1,458,780 | 1,285,705 | 1,425,949 | 1,140,020 | 1,337,016 | 1,277,913 | 1,495,017 | 1,864,447 | 1,680,097 | 1,360,531 |
| 2032 | 1,172,307 | 1,184,680 | 1,140,766 | 1,028,873 | 1,130,518 | 1,154,399 | 1,345,738 | 1,686,763 | 1,343,955 | 1,073,175 |
| 2033 | 1,088,608 | 1,139,628 | 1,137,758 | 970,416 | 1,074,124 | 1,063,863 | 1,249,073 | 1,642,284 | 1,633,253 | 1,082,760 |
| 2034 | 1,102,207 | 1,014,563 | 1,129,448 | 1,038,398 | 1,147,504 | 1,016,265 | 1,418,127 | 1,736,761 | 1,607,203 | 1,185,587 |
| 2035 | 969,045 | 954,940 | 1,017,423 | 930,579 | 962,194 | 875,927 | 1,141,263 | 1,070,749 | 1,209,862 | 1,000,129 |
| 2036 | 1,077,427 | 1,113,226 | 1,083,840 | 1,006,886 | 1,091,843 | 819,126 | 1,290,885 | 1,272,803 | 1,326,011 | 1,229,695 |
| 2037 | 1,090,301 | 1,096,750 | 1,064,933 | 1,099,131 | 1,112,048 | 779,574 | 1,280,417 | 1,260,130 | 1,303,552 | 1,186,632 |
| 2038 | 743,217 | 806,782 | 628,576 | 753,154 | 774,355 | 594,170 | 912,474 | 1,014,657 | 790,423 | 896,369 |
| 2039 | 685,923 | 731,854 | 616,514 | 685,672 | 707,627 | 521,610 | 878,149 | 1,011,587 | 800,412 | 789,588 |
| 2040 | 622,696 | 679,881 | 574,580 | 628,354 | 674,372 | 520,401 | 825,877 | 847,676 | 711,556 | 719,350 |
| 2041 | 673,577 | 731,911 | 580,115 | 645,700 | 655,082 | 525,143 | 812,933 | 989,300 | 798,559 | 726,832 |
| 2042 | 642,186 | 673,392 | 601,119 | 635,835 | 676,903 | 497,737 | 869,267 | 948,793 | 752,595 | 759,144 |
| 2043 | 607,501 | 607,373 | 543,147 | 597,090 | 578,131 | 529,398 | 803,878 | 846,165 | 775,112 | 650,958 |
| **Total** | **30,414,704** | **30,405,231** | **30,084,630** | **28,899,086** | **30,083,409** | **28,817,444** | **34,226,528** | **36,303,324** | **34,243,917** | **31,337,010** |

## Scenarios and Sensitivities $CO_2$ Emissions (Metric Tons)

| Year | Clean by 2045 | Clean by 2035 | High Gas High Carbon | Low Gas Zero Carbon | Constrained Storage | Additional Large Load (100 MW) | Additional Large Load (200 MW) | New Forecasted PURPA | Extreme Weather | Rapid Electrification (ASHP) | Rapid Electrification (GSHP) | Load Flattening |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | 2,572,462 | 2,788,395 | 2,459,954 | 3,413,958 | 2,819,296 | 3,392,946 | 3,376,949 | 3,275,537 | 2,893,122 | 3,474,577 | 3,469,601 | 3,357,763 |
| 2025 | 3,259,121 | 3,223,349 | 2,306,435 | 3,543,104 | 3,065,046 | 3,532,625 | 3,535,449 | 3,475,413 | 3,100,913 | 3,705,229 | 3,677,727 | 3,523,437 |
| 2026 | 2,406,086 | 2,597,012 | 1,925,374 | 3,216,503 | 3,279,298 | 3,621,864 | 3,660,011 | 3,548,596 | 3,393,467 | 3,785,269 | 3,781,453 | 3,566,612 |
| 2027 | 2,489,885 | 2,317,189 | 1,638,136 | 3,076,668 | 2,502,057 | 2,554,003 | 2,652,083 | 2,464,076 | 2,669,099 | 3,081,909 | 3,016,419 | 2,520,532 |
| 2028 | 1,596,254 | 1,542,255 | 1,550,767 | 3,256,017 | 2,205,721 | 2,384,873 | 2,495,377 | 2,338,139 | 2,402,382 | 3,113,073 | 3,108,384 | 2,418,106 |
| 2029 | 1,413,765 | 1,370,321 | 1,529,683 | 3,174,843 | 2,181,757 | 2,161,617 | 2,176,872 | 2,186,954 | 2,306,365 | 3,483,681 | 3,575,556 | 2,135,205 |
| 2030 | 1,047,247 | 1,090,560 | 1,230,354 | 2,365,063 | 1,490,599 | 1,465,961 | 1,385,654 | 1,632,989 | 1,647,326 | 2,330,532 | 2,522,836 | 1,383,329 |
| 2031 | 916,489 | 929,948 | 866,374 | 2,160,803 | 1,217,032 | 1,383,323 | 1,262,529 | 1,410,813 | 1,456,834 | 2,226,891 | 2,434,331 | 1,250,750 |
| 2032 | 876,033 | 829,906 | 910,590 | 2,207,182 | 1,218,345 | 1,202,806 | 1,172,400 | 1,356,313 | 1,417,330 | 2,051,860 | 2,423,357 | 1,118,555 |
| 2033 | 746,999 | 1,067,784 | 846,866 | 2,353,038 | 1,534,567 | 1,142,774 | 1,020,460 | 1,351,844 | 2,288,038 | 1,220,937 | 1,342,934 | 1,052,518 |
| 2034 | 694,949 | 656,800 | 746,704 | 2,229,880 | 1,417,643 | 1,177,205 | 1,161,662 | 1,455,013 | 1,555,519 | 976,138 | 1,078,904 | 1,137,265 |
| 2035 | 668,646 | 0 | 857,657 | 2,187,898 | 1,258,748 | 990,771 | 1,029,449 | 1,144,189 | 1,416,909 | 1,156,242 | 1,373,717 | 1,030,143 |
| 2036 | 702,143 | 0 | 818,176 | 2,132,573 | 1,077,717 | 1,161,334 | 1,178,978 | 1,311,954 | 1,560,046 | 1,244,090 | 1,395,180 | 1,207,898 |
| 2037 | 733,896 | 0 | 826,401 | 1,647,646 | 950,335 | 1,202,837 | 1,196,169 | 1,283,968 | 1,368,145 | 1,315,306 | 1,575,520 | 1,198,405 |
| 2038 | 592,944 | 0 | 569,757 | 1,363,592 | 851,923 | 813,425 | 863,271 | 733,943 | 1,011,075 | 1,042,721 | 1,179,398 | 902,311 |
| 2039 | 504,911 | 0 | 582,999 | 1,129,455 | 547,078 | 771,230 | 815,822 | 697,520 | 748,979 | 921,425 | 946,707 | 813,825 |
| 2040 | 479,076 | 0 | 531,306 | 1,163,529 | 494,451 | 708,366 | 702,658 | 634,022 | 584,837 | 873,019 | 1,015,758 | 777,044 |
| 2041 | 423,743 | 0 | 498,185 | 1,617,905 | 461,334 | 703,574 | 725,831 | 693,229 | 619,930 | 911,629 | 1,015,080 | 751,549 |
| 2042 | 419,399 | 0 | 465,932 | 1,603,036 | 470,795 | 752,596 | 751,711 | 670,367 | 563,178 | 932,952 | 1,026,588 | 817,762 |
| 2043 | 418,697 | 0 | 477,896 | 1,671,359 | 369,659 | 646,428 | 664,168 | 653,545 | 460,393 | 763,139 | 870,710 | 681,926 |
| **Total** | **22,962,745** | **18,413,520** | **21,639,546** | **45,514,053** | **29,413,400** | **31,770,558** | **31,827,503** | **32,318,424** | **33,463,885** | **38,610,619** | **40,830,159** | **31,644,936** |

## *Main Cases $SO_2$ Emissions (Metric Tons)*

| Year | Jul 2026 B2H | | | Nov 2026 B2H | | | Without B2H | GWW Sensitivities | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without B2H | Without GWW Phases | GWW Phase 1 Only | GWW Phase 1 & 2 Only |
| 2024 | 1,110 | 1,114 | 1,104 | 1,115 | 1,106 | 1,092 | 1,218 | 1,112 | 1,107 | 1,110 |
| 2025 | 1,316 | 1,316 | 1,319 | 1,314 | 1,318 | 1,302 | 1,321 | 1,315 | 1,318 | 1,316 |
| 2026 | 1,380 | 1,388 | 1,399 | 1,342 | 1,360 | 1,376 | 1,400 | 1,400 | 1,372 | 1,396 |
| 2027 | 1,036 | 1,031 | 1,060 | 989 | 1,010 | 1,091 | 1,121 | 1,079 | 1,106 | 1,044 |
| 2028 | 1,017 | 1,032 | 1,032 | 971 | 1,008 | 1,033 | 1,074 | 1,085 | 1,133 | 1,033 |
| 2029 | 881 | 825 | 895 | 814 | 837 | 891 | 849 | 863 | 955 | 858 |
| 2030 | 40 | 41 | 47 | 41 | 46 | 43 | 46 | 59 | 60 | 46 |
| 2031 | 38 | 40 | 40 | 36 | 41 | 41 | 39 | 62 | 60 | 43 |
| 2032 | 55 | 54 | 56 | 51 | 58 | 59 | 56 | 78 | 68 | 59 |
| 2033 | 58 | 57 | 58 | 54 | 63 | 59 | 57 | 80 | 66 | 59 |
| 2034 | 60 | 61 | 61 | 57 | 64 | 58 | 54 | 80 | 69 | 60 |
| 2035 | 42 | 41 | 43 | 40 | 44 | 41 | 43 | 55 | 50 | 43 |
| 2036 | 34 | 34 | 35 | 32 | 37 | 33 | 36 | 50 | 43 | 36 |
| 2037 | 32 | 32 | 34 | 31 | 36 | 30 | 35 | 48 | 41 | 34 |
| 2038 | 60 | 59 | 62 | 56 | 67 | 62 | 63 | 95 | 78 | 63 |
| 2039 | 74 | 72 | 75 | 71 | 77 | 81 | 67 | 107 | 95 | 76 |
| 2040 | 70 | 66 | 67 | 64 | 66 | 73 | 70 | 104 | 89 | 71 |
| 2041 | 64 | 63 | 64 | 62 | 63 | 69 | 66 | 96 | 89 | 75 |
| 2042 | 60 | 61 | 63 | 58 | 59 | 65 | 65 | 96 | 81 | 72 |
| 2043 | 51 | 55 | 52 | 49 | 50 | 57 | 54 | 89 | 77 | 61 |
| **Total** | **7,477** | **7,442** | **7,565** | **7,248** | **7,411** | **7,556** | **7,735** | **7,954** | **7,957** | **7,557** |

## *Scenarios and Sensitivities $SO_2$ Emissions (Metric Tons)*

| Year | Clean by 2045 | Clean by 2035 | High Gas High Carbon | Low Gas Zero Carbon | Constrained Storage | Additional Large Load (100 MW) | Additional Large Load (200 MW) | New Forecasted PURPA | Extreme Weather | Rapid Electrification (ASHP) | Rapid Electrification (GSHP) | Load Flattening |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | 638 | 648 | 755 | 1,135 | 927 | 1,120 | 1,113 | 1,088 | 952 | 1,166 | 1,164 | 1,112 |
| 2025 | 1,126 | 1,012 | 727 | 1,257 | 1,150 | 1,320 | 1,316 | 1,290 | 1,168 | 1,366 | 1,357 | 1,311 |
| 2026 | 898 | 936 | 691 | 1,148 | 1,330 | 1,411 | 1,408 | 1,376 | 1,365 | 1,425 | 1,421 | 1,389 |
| 2027 | 1,219 | 1,112 | 643 | 1,082 | 1,130 | 1,067 | 1,102 | 1,058 | 1,127 | 1,203 | 1,186 | 1,061 |
| 2028 | 675 | 693 | 597 | 1,172 | 1,033 | 1,058 | 1,083 | 1,067 | 1,058 | 1,258 | 1,247 | 1,077 |
| 2029 | 381 | 358 | 544 | 1,101 | 897 | 898 | 876 | 922 | 913 | 1,075 | 1,081 | 890 |
| 2030 | 40 | 41 | 27 | 45 | 48 | 47 | 49 | 44 | 50 | 55 | 50 | 52 |
| 2031 | 31 | 29 | 22 | 47 | 45 | 44 | 43 | 37 | 51 | 58 | 58 | 43 |
| 2032 | 28 | 28 | 22 | 45 | 44 | 61 | 60 | 51 | 51 | 53 | 51 | 60 |
| 2033 | 46 | 34 | 24 | 52 | 85 | 62 | 63 | 52 | 103 | 51 | 50 | 64 |
| 2034 | 38 | 13 | 18 | 50 | 66 | 63 | 64 | 54 | 67 | 52 | 57 | 65 |
| 2035 | 32 | 0 | 21 | 60 | 54 | 44 | 45 | 37 | 56 | 42 | 42 | 47 |
| 2036 | 33 | 0 | 22 | 52 | 49 | 37 | 37 | 31 | 57 | 40 | 39 | 39 |
| 2037 | 34 | 0 | 24 | 39 | 42 | 36 | 36 | 29 | 48 | 43 | 43 | 37 |
| 2038 | 67 | 0 | 58 | 77 | 95 | 68 | 68 | 46 | 77 | 124 | 115 | 72 |
| 2039 | 66 | 0 | 57 | 87 | 107 | 82 | 83 | 55 | 107 | 132 | 124 | 89 |
| 2040 | 59 | 0 | 57 | 105 | 77 | 70 | 78 | 50 | 78 | 131 | 130 | 79 |
| 2041 | 85 | 0 | 53 | 152 | 71 | 69 | 75 | 50 | 75 | 123 | 132 | 77 |
| 2042 | 81 | 0 | 71 | 141 | 78 | 68 | 71 | 49 | 85 | 119 | 132 | 71 |
| 2043 | 84 | 0 | 60 | 151 | 67 | 55 | 63 | 42 | 64 | 110 | 122 | 62 |
| **Total** | **5,662** | **4,903** | **4,494** | **7,998** | **7,395** | **7,679** | **7,733** | **7,429** | **7,553** | **8,629** | **8,599** | **7,698** |

## *Main Cases NOx Emissions (Metric Tons)*

| Year | Jul 2026 B2H | | | Nov 2026 B2H | | | Without B2H | GWW Sensitivities | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without Valmy | Valmy 2 | Valmy 1 & 2 | Without B2H | Without GWW Phases | GWW Phase 1 Only | GWW Phase 1 & 2 Only |
| 2024 | 1,859 | 1,853 | 1,849 | 1,870 | 1,855 | 1,832 | 1,966 | 1,863 | 1,851 | 1,851 |
| 2025 | 1,849 | 1,859 | 1,867 | 1,862 | 1,867 | 1,839 | 1,879 | 1,851 | 1,860 | 1,845 |
| 2026 | 1,654 | 1,641 | 1,685 | 1,610 | 1,631 | 1,666 | 1,646 | 1,661 | 1,598 | 1,613 |
| 2027 | 980 | 1,020 | 986 | 872 | 925 | 987 | 1,020 | 1,088 | 1,042 | 1,005 |
| 2028 | 931 | 919 | 925 | 795 | 852 | 890 | 937 | 996 | 999 | 953 |
| 2029 | 764 | 783 | 895 | 733 | 779 | 813 | 777 | 838 | 786 | 791 |
| 2030 | 740 | 787 | 994 | 738 | 756 | 925 | 638 | 795 | 806 | 827 |
| 2031 | 769 | 765 | 963 | 676 | 775 | 862 | 595 | 729 | 777 | 805 |
| 2032 | 622 | 738 | 742 | 618 | 645 | 756 | 495 | 641 | 611 | 608 |
| 2033 | 535 | 726 | 758 | 606 | 641 | 673 | 482 | 651 | 648 | 631 |
| 2034 | 532 | 577 | 661 | 588 | 639 | 457 | 560 | 528 | 536 | 641 |
| 2035 | 446 | 509 | 561 | 520 | 502 | 377 | 447 | 405 | 449 | 500 |
| 2036 | 598 | 684 | 678 | 641 | 662 | 392 | 621 | 553 | 594 | 719 |
| 2037 | 588 | 670 | 659 | 655 | 658 | 415 | 614 | 551 | 569 | 700 |
| 2038 | 415 | 498 | 471 | 481 | 535 | 269 | 386 | 351 | 277 | 511 |
| 2039 | 299 | 310 | 489 | 306 | 407 | 228 | 257 | 337 | 307 | 326 |
| 2040 | 280 | 281 | 455 | 265 | 373 | 218 | 254 | 287 | 285 | 301 |
| 2041 | 307 | 324 | 446 | 300 | 402 | 227 | 249 | 326 | 320 | 323 |
| 2042 | 306 | 313 | 551 | 297 | 423 | 185 | 288 | 341 | 302 | 340 |
| 2043 | 267 | 264 | 478 | 263 | 332 | 203 | 262 | 315 | 312 | 286 |
| **Total** | **14,740** | **15,522** | **17,112** | **14,695** | **15,659** | **14,214** | **14,374** | **15,105** | **14,927** | **15,576** |

## *Scenarios and Sensitivities NOx Emissions (Metric Tons)*

| Year | Clean by 2045 | Clean by 2035 | High Gas High Carbon | Low Gas Zero Carbon | Constrained Storage | Additional Large Load (100 MW) | Additional Large Load (200 MW) | New Forecasted PURPA | Extreme Weather | Rapid Electrification (ASHP) | Rapid Electrification (GSHP) | Load Flattening |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | 1,507 | 1,721 | 1,135 | 1,885 | 1,534 | 1,872 | 1,869 | 1,797 | 1,589 | 1,928 | 1,926 | 1,842 |
| 2025 | 1,741 | 1,800 | 994 | 1,921 | 1,583 | 1,862 | 1,866 | 1,846 | 1,596 | 1,985 | 1,968 | 1,858 |
| 2026 | 1,141 | 1,225 | 713 | 1,656 | 1,523 | 1,652 | 1,700 | 1,624 | 1,555 | 1,762 | 1,760 | 1,633 |
| 2027 | 1,027 | 947 | 602 | 1,602 | 1,006 | 1,042 | 1,123 | 994 | 1,097 | 1,304 | 1,295 | 1,032 |
| 2028 | 673 | 658 | 575 | 1,700 | 865 | 955 | 1,016 | 912 | 970 | 1,329 | 1,326 | 969 |
| 2029 | 516 | 617 | 479 | 1,711 | 770 | 903 | 920 | 898 | 861 | 1,232 | 1,329 | 888 |
| 2030 | 447 | 603 | 428 | 1,363 | 742 | 861 | 763 | 1,022 | 798 | 1,094 | 1,216 | 771 |
| 2031 | 374 | 568 | 274 | 1,316 | 599 | 789 | 721 | 836 | 718 | 1,064 | 1,216 | 706 |
| 2032 | 366 | 540 | 310 | 1,333 | 624 | 758 | 719 | 894 | 787 | 990 | 1,212 | 618 |
| 2033 | 346 | 834 | 289 | 1,409 | 773 | 650 | 582 | 910 | 1,302 | 548 | 639 | 669 |
| 2034 | 340 | 543 | 197 | 1,327 | 695 | 665 | 625 | 868 | 792 | 254 | 482 | 622 |
| 2035 | 388 | 18 | 306 | 1,277 | 640 | 501 | 521 | 655 | 705 | 430 | 609 | 516 |
| 2036 | 398 | 17 | 282 | 1,276 | 536 | 693 | 712 | 786 | 801 | 457 | 620 | 724 |
| 2037 | 452 | 48 | 297 | 1,051 | 492 | 697 | 680 | 750 | 717 | 494 | 697 | 689 |
| 2038 | 213 | 64 | 158 | 647 | 431 | 513 | 506 | 423 | 478 | 307 | 404 | 532 |
| 2039 | 117 | 58 | 163 | 423 | 206 | 420 | 334 | 441 | 290 | 216 | 224 | 353 |
| 2040 | 126 | 60 | 152 | 387 | 192 | 362 | 294 | 379 | 243 | 196 | 228 | 326 |
| 2041 | 173 | 61 | 139 | 519 | 196 | 394 | 311 | 481 | 265 | 206 | 248 | 333 |
| 2042 | 187 | 62 | 158 | 536 | 189 | 442 | 333 | 465 | 268 | 207 | 246 | 376 |
| 2043 | 184 | 42 | 155 | 573 | 152 | 347 | 286 | 475 | 198 | 184 | 213 | 287 |
| **Total** | **10,717** | **10,488** | **7,807** | **23,913** | **13,747** | **16,378** | **15,881** | **17,456** | **16,032** | **16,190** | **17,859** | **15,744** |

# STOCHASTIC RISK ANALYSIS

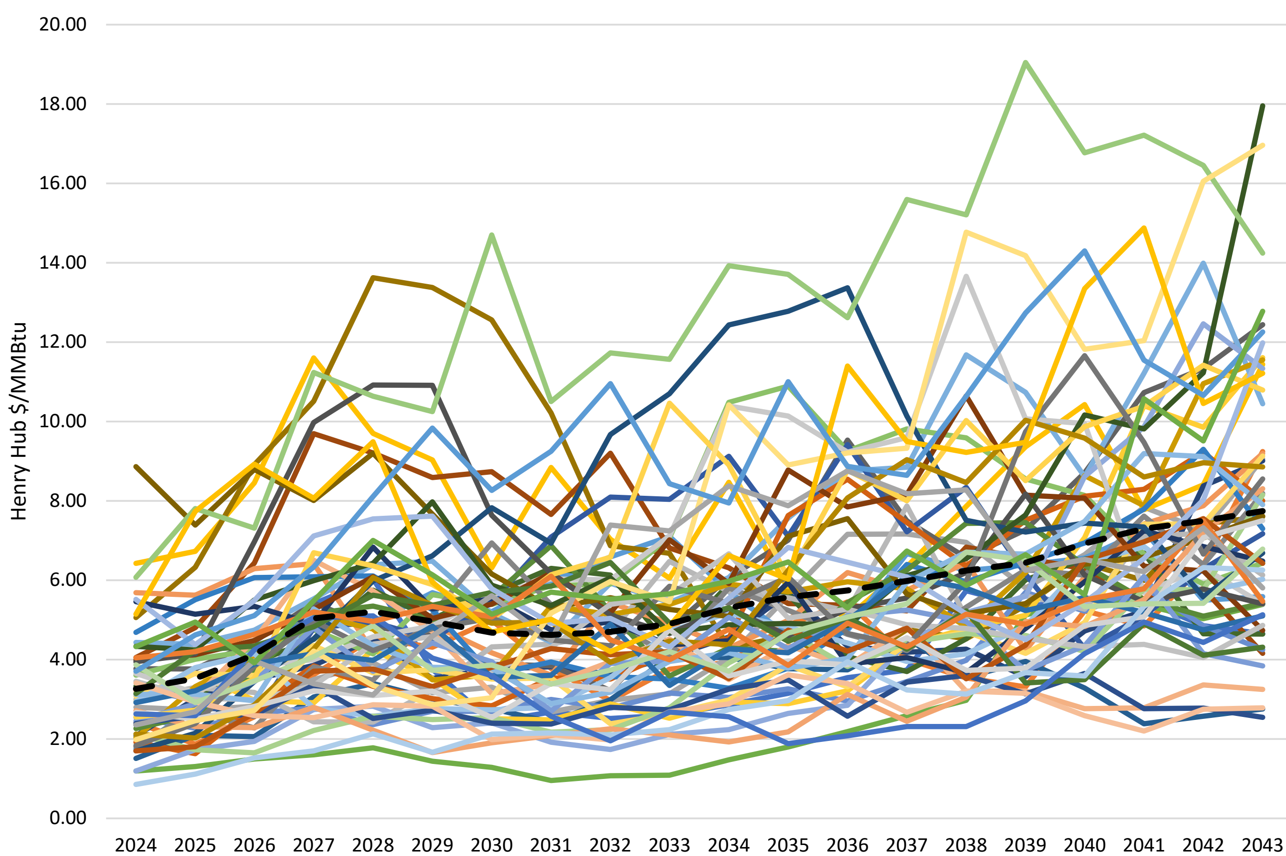
The stochastic analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and the degree to which they can affect the analysis results (i.e., portfolio costs).

The purpose of the analysis is to understand the range of portfolio costs across a wide extent of stochastic shocks (i.e., across the full set of 60 stochastic iterations) and how the ranges for portfolios costs differ.

Idaho Power identified the following four variables for the stochastic analysis:

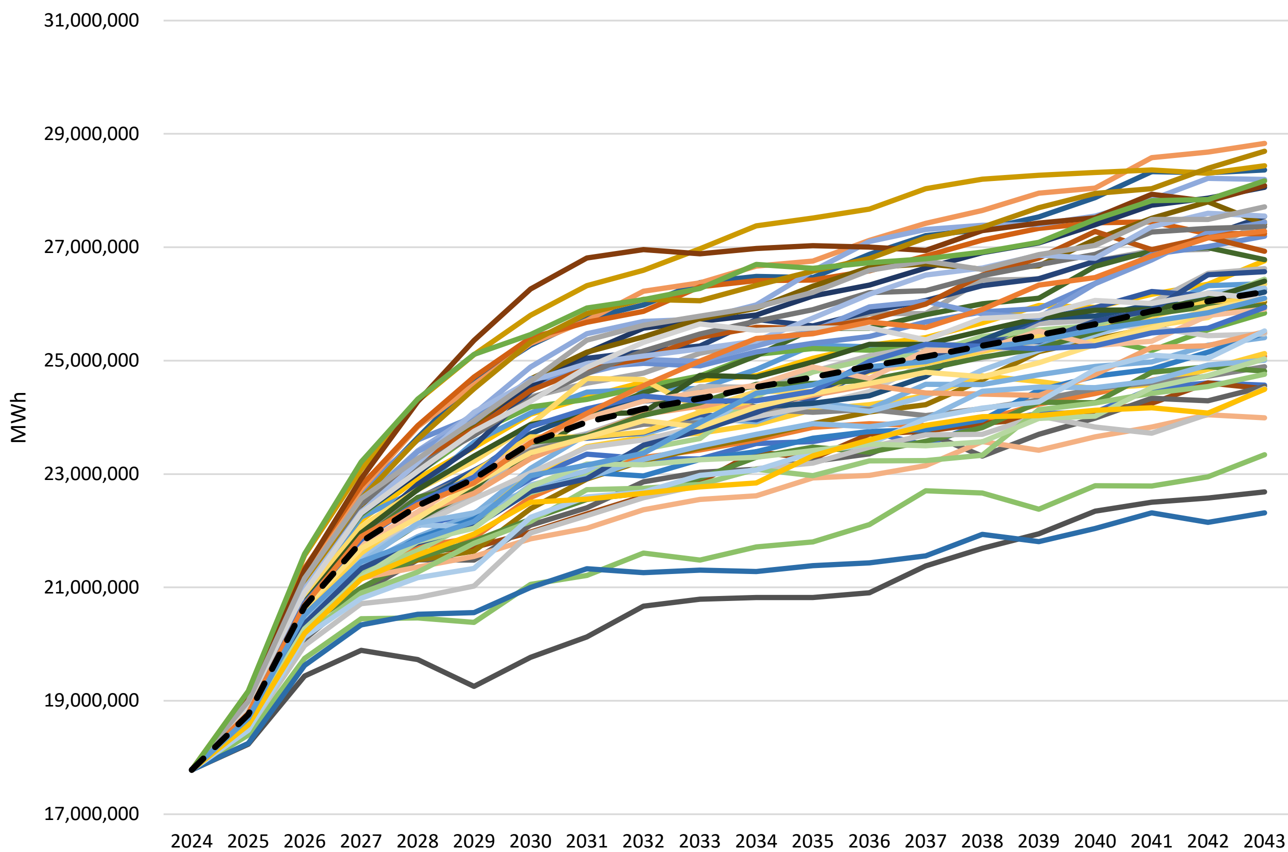
## Natural Gas Sampling (Nominal $/MMBtu)

1. *Natural gas price*—Based on the historical Henry Hub natural gas price, 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 60 different stochastic iterations for Henry Hub gas prices.



## Customer Load Sampling (Annual MWh)

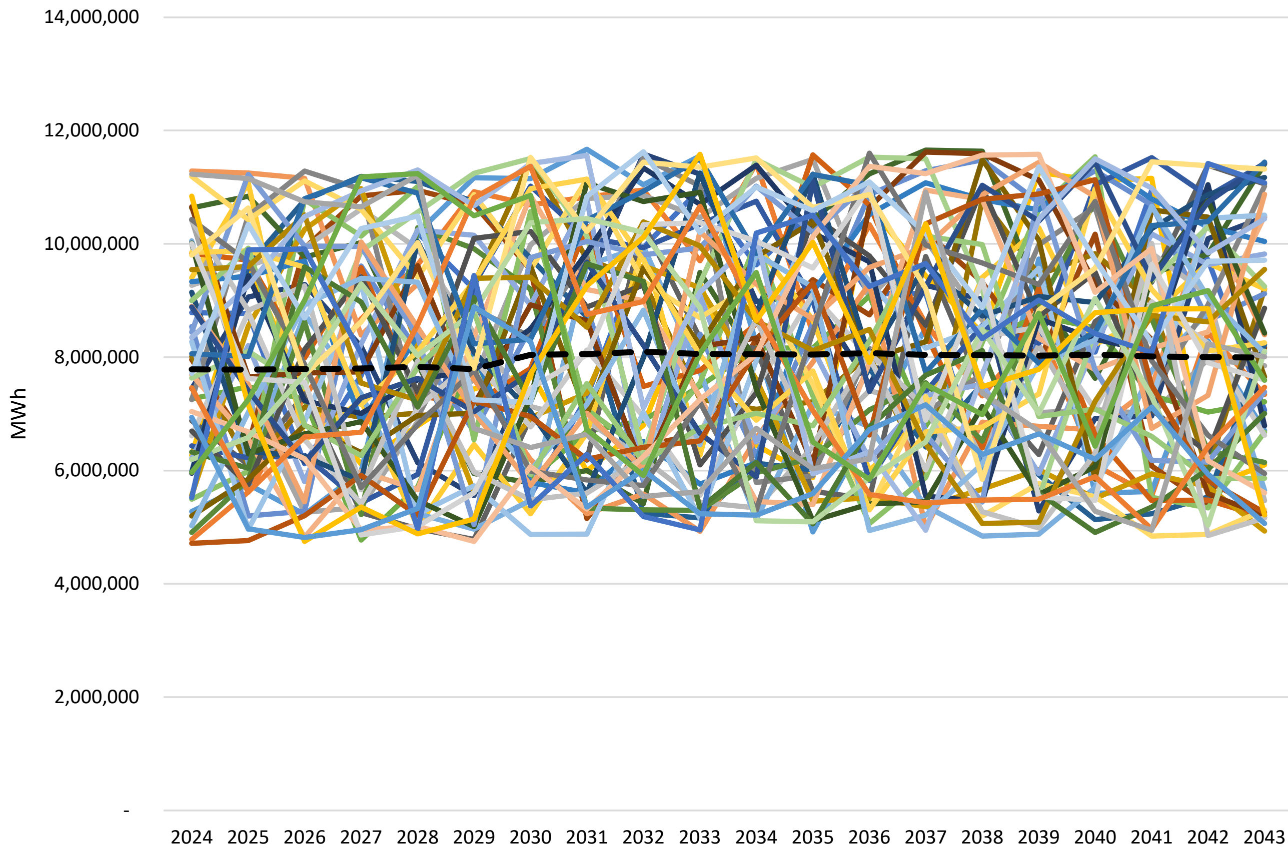
2. *Customer load*—Customer load follows a normal distribution and is adjusted around the planning case load forecast, which is shown as the dashed line in the figure below. To assess the reasonableness of the stochastic error bounds as they relate to customer load, the upper and lower bounds were compared 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.




## Hydro Generation Sampling (Annual MWh)

3. *Hydroelectric variability*—Hydroelectric generation variability was found to approximate a uniform distribution based on historical generation. 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.

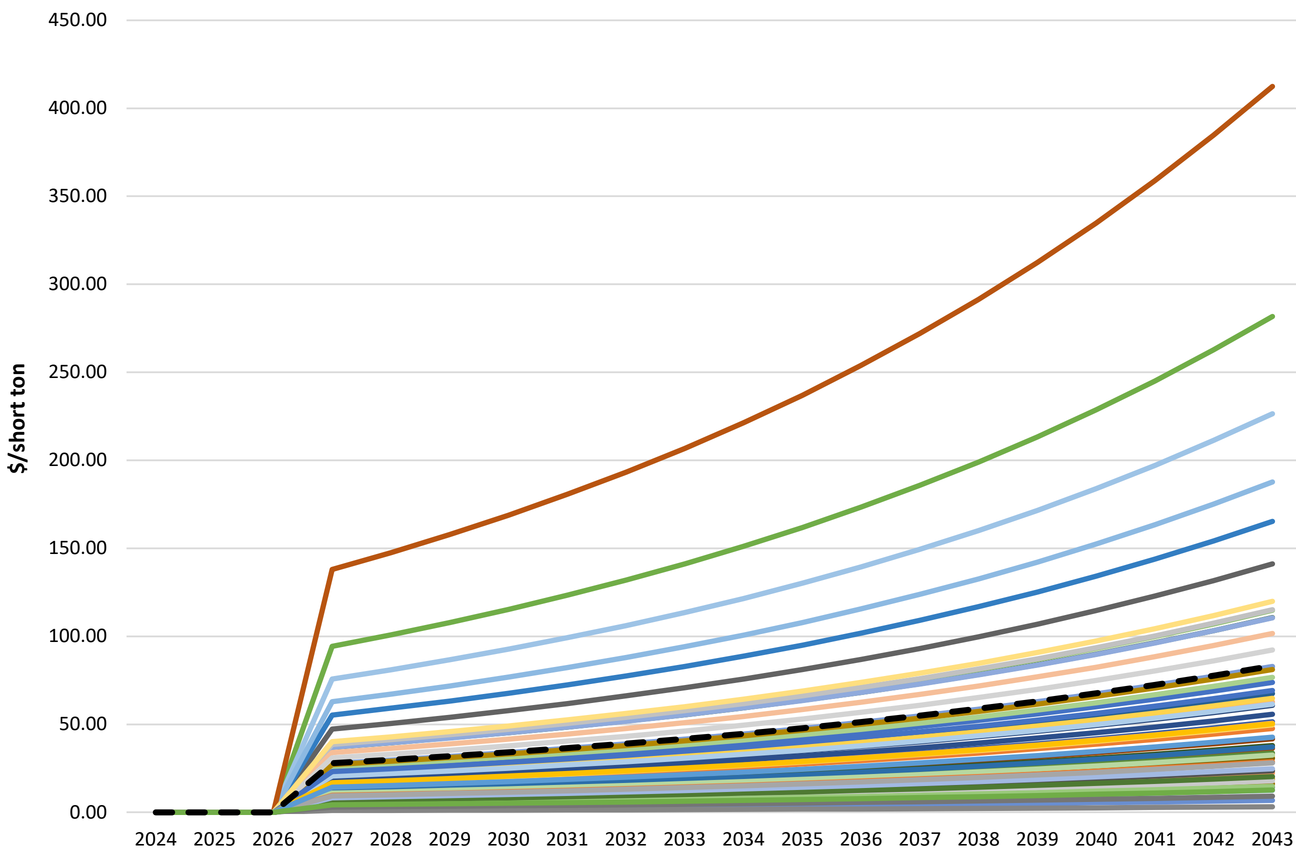



## Carbon Price Sampling (Annual MWh)

4. *Carbon Price*—Though historical carbon price adder prices have always been zero, a wide-range of possible values are modeled into the future. The stochastic lower bound was set near zero and the upper bound was set to roughly approximate the Social Cost of Carbon[1] curve after

[1] epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf, page 67, retrieved September 7 2023

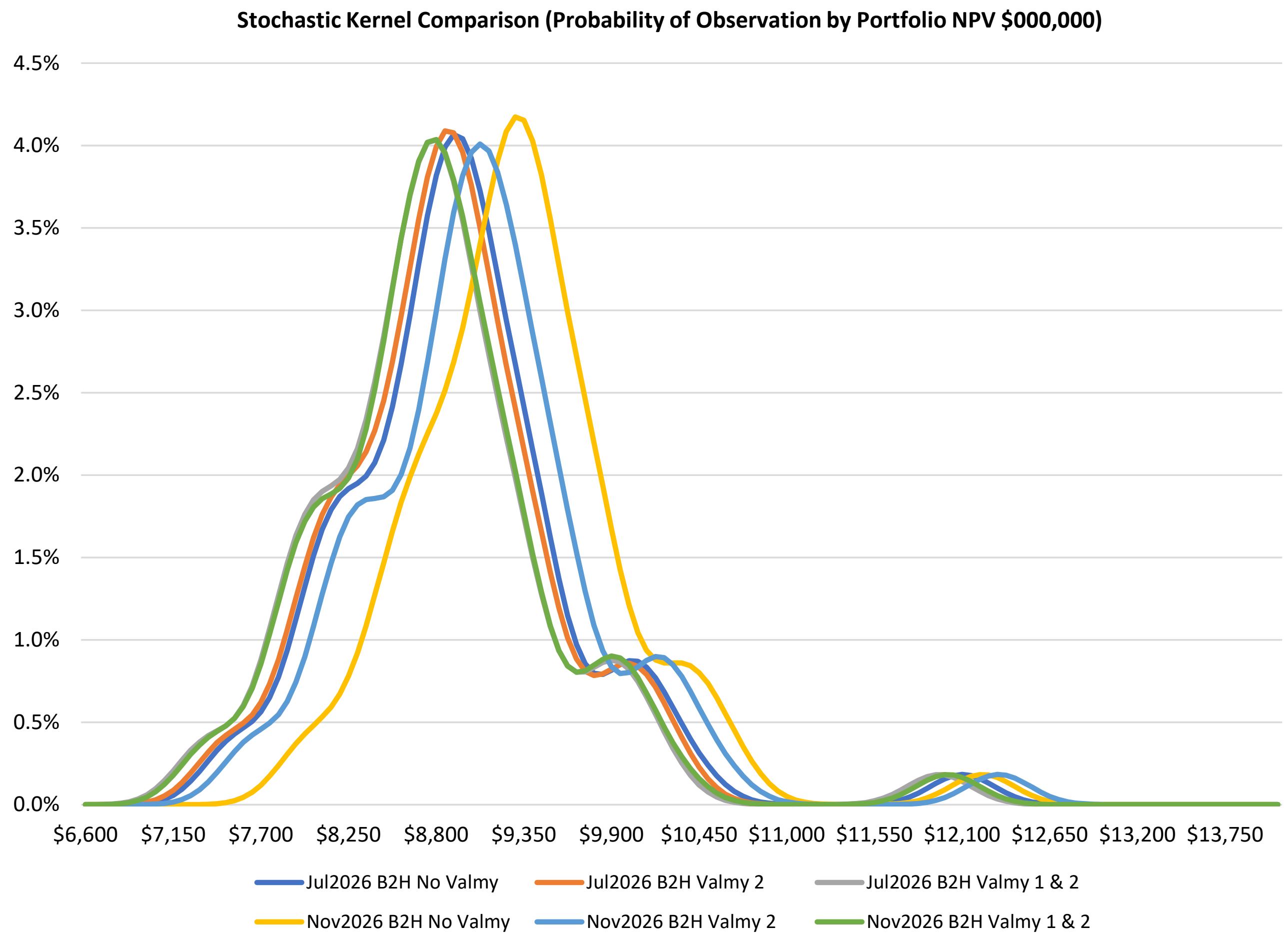
discussions with IRPAC. Stochastic values were then produced such that the average of all the values approximated the planning carbon price adder case.




The four 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 60 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 60 iterations to ensure a good distribution of draws. Once the stochastic elements are drawn, the company then calculated the

20-year NPV portfolio cost for each of the 60 iterations for all evaluated portfolios. The graph below shows the distribution of 20-year NPV portfolio costs for the portfolios.




## Portfolio Stochastic Analysis, Total Portfolio Cost

### *NPV Years 2024–2043 ($ x 1,000)*

In the figure above, each line represents the likelihood of occurrence by NPV. Higher values on the line represent a higher probability of occurrence with values near the horizontal axis representing improbable events. Values that occur toward the left have lower cost while values toward the right have higher cost. As indicated by the peak of the graph being furthest left, the results of the stochastic analysis show that the Preferred Portfolio is likely to have the lowest cost given a range of natural gas prices, load forecasts, carbon prices, and hydroelectric generation levels. Indeed, in all 60 risk iterations spanning the range of stochastic variables, the Preferred Portfolio (Jul2026 B2H Valmy 1 & 2) was the least-cost option.

# 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 (VER) and Energy Limited Resources (ELR) have on system reliability.

VER: Variable energy resources include those whose generation is dependent upon weather, for example, solar and wind projects.

ELR: Energy limited resources are those whose generation can be called upon but are only able to dispatch for a limited amount of time and under certain conditions, for example, battery storage projects and demand response programs.

For the 2023 IRP, Idaho Power used the risk-based equations and methodologies described in this section to calculate the capacity contribution of different VERs and ELRs for the AURORA LTCE model and quantitatively analyze the risk associated with the portfolios. The company chose to conduct this study because of the recognition that VER output changes over time (VER hourly output being dependent on a multitude of factors like weather and environmental conditions) and that it is essential to capture that variability.

## 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 net 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 $i$. For the 2023 IRP, Idaho Power has adopted a LOLE threshold of 0.1 event-days per year.

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 driven by the timing of high LOLP hours. To calculate the ELCC of a resource, there are two definitions that should first be stated:

| | |
|---|---|
| EFORd: | The Equivalent Forced Outage Rate during Demand (EFORd) represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs; for example, an EFORd of 3% means a generator is forced off 3% of its running time. |
| Perfect Generator: | A generation unit whose EFORd value is 0%, 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 a LOLE of 0.1 event-days per year. 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:

$$ELCC = \frac{PG_1 - PG_2}{Resource_{NM}} * 100$$

where $PG_1$ is the perfect generation required to achieve a LOLE of 0.1 event-days per year without including the evaluated resource, $PG_2$ is the perfect generation required to achieve the same LOLE of 0.1 event-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 developed the Reliability and Capacity Assessment Tool (RCAT) 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 categories: dispatchable resources, VERs, and ELRs. Dispatchable resources were modeled using a monthly outage table that was calculated using their monthly capacity and EFORd. 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 |

Existing dispatchable resources include hydro with reservoir storage (the Hells Canyon Complex), thermal resources, and various transmission assets with access to the market.

VERs were modeled by using six 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 dispatch were also modeled using the six years of historical hourly output data. Examples of these resources include dairy digestors, non-wind and non-solar PURPA projects, ROR 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 battery storage and demand response, are dispatched based on the daily load shape, Idaho Power devised a separate way to model ELRs. The RCAT begins by sorting the days in a year from high to low based on their net load peak. After verifying that the operating parameters of the demand response portfolio or storage resource are met on that day, the algorithm optimizes the daily dispatch based on the sorted updated net load.

This customization functionality of the RCAT allows for a detailed approach to modeling Idaho Power's system. As system needs continue to change, new analyses such as LOLE are essential in best evaluating the company's reliability and highest-risk hours.

### *Western Resource Adequacy Program Modeling*

The Western Resource Adequacy Program (WRAP) is a regional planning and capacity-sharing program in which Idaho Power is a participant. The function and purpose of WRAP is provided in Chapter 2 of the IRP. Because the WRAP is designed as program of last resort, Idaho Power assumed for the 2023 IRP that it will leverage WRAP only once per year. As Idaho Power gains operational experience with WRAP, the company will develop a more refined understanding of how often it is likely to leverage the WRAP operations program.

To model the benefit of leveraging WRAP once per year, Idaho Power first performed an LOLP analysis on six historical test years of load and resource data and identified the highest-risk day in each historical test year. Using Idaho Power's RCAT, 100 MW of capacity was then added to the resource stack for each of the six identified highest-risk days. The 100 MW resource addition represents the amount of capacity leveraged from WRAP required to bring the LOLP values of the highest-risk day in the worst-performing historical test year down to a similar risk profile as other days in that year.

The RCAT analysis found that, on average, an additional 100 MW from WRAP on the company's highest-risk day results in Idaho Power needing 14 MW *less* perfect generation to meet a 0.1 event-days per year LOLE. In other words, leveraging WRAP to significantly reduce the risk of the highest-risk day each year is the equivalent of avoiding 14 MW of perfect generation.

For the 2023 IRP, Idaho Power included the 14 MW of WRAP capacity benefit beginning in 2027—the assumed date of binding participation—and continuing each year through the planning horizon. Idaho Power is working with other WRAP participants to align on a collective binding date. Should that date change from 2027, the company will adjust the first benefit year in future IRPs.

## Effective Load-Carrying Capability Results

The ELCC of future VERs and ELRs are dependent upon the resources built before them, making the ELCC calculation of future resources challenging. For the 2023 IRP AURORA LTCE model, Idaho Power implemented seasonal saturation ELCC curves for each of the VERs and ELRs. The seasonal saturation ELCC curves assist in synchronizing the RCAT and AURORA models in terms of recognizing similar capacity needs and allow for recognition of how quickly a particular resource can become saturated. For example, the capacity contribution of solar during the summer declines as the net peak shifts to later in the day; however, during the winter, solar has a significantly lower capacity contribution when the highest-risk hours (typically) occur outside the limited sunlight hours.

The ELCC of future and existing resources can be calculated by using the "last-in" ELCC method, where each resource is assumed to be the last one added to the mix independent of the order on which they were added to the system. For example, the ELCC of demand response appears to be lower than in past IRPs but it is primarily due to the amount of battery storage included in the resource buildout. The ELCC values in the table below are provided for informational purposes.

| ELCC of Existing and Expected Resources | | ELCC of Future Resources | |
|---|---|---|---|
| **Resource** | **Average** | **Resource** | **Average** |
| Solar | 51.3% | Solar | 27.7% |
| Wind | 20.0% | Wind (ID) | 15.5% |
| Demand Response | 34.0% | Wind (WY) | 20.8% |
| 4-Hour Stand-Alone Battery Storage | 81.2% | 4-Hour Stand-Alone Battery Storage | 38.5% |
| Solar + 4-Hour Battery Storage (1:1) | 85.1% | 8-Hour Stand-Alone Battery Storage | 79.2% |
| Solar + 4-Hour Battery Storage (1:0.6) | 61.2% | Incremental Existing Demand Response | 19.4% |
| | | Storage Demand Response | 35.0% |
| | | Pricing Demand Response | 32.2% |

## Timing of Highest Risk

The calculation of LOLE involves determining the LOLP for each hour, which Idaho Power performs for each of the test years used in the RCAT. In terms of capacity, the hourly LOLP values were used to determine the seasons and hours of highest risk for the 2023 IRP.

The seasons of highest risk were determined by first selecting the LOLP values that made up 90% of the total hourly risk (i.e., sum of all LOLPs). These LOLPs were then grouped by their time of occurrence to create the seasons of highest risk. The seasons of highest risk for the 2023 IRP were identified to be November 1 through February 28 for winter and June 1 through September 15 for summer.

To establish the hours of medium and highest risk, the RCAT was set to select the top LOLP daily hours that resulted in 50% of the risk of each month in the season for each of the test years; the results from the different test years were then combined. Using the test year combined top LOLP hours, a percent of occurrences threshold was developed to identify the medium-risk and high-risk hours.

The 2023 IRP hours of high, medium, and low risk by season are provided in the tables below.

### Summer Risk Hours (June 1–September 15)

| Hour End | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 2 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 3 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 4 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 5 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 6 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 7 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 8 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 9 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 10 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 11 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 12 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 13 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 14 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 15 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 16 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 17 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |
| 18 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 19 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 20 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 21 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 22 | SLR | SHR | SHR | SHR | SHR | SHR | SHR | SLR |
| 23 | SLR | SMR | SMR | SMR | SMR | SMR | SMR | SLR |
| 24 | SLR | SLR | SLR | SLR | SLR | SLR | SLR | SLR |

SLR—Summer Low-Risk
SMR—Summer Medium-Risk
SHR—Summer High-Risk

## *Winter Risk Hours (November 1–February 28/29)*

| Hour End | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 2 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 3 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 4 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 5 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 6 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 7 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 8 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 9 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 10 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 11 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 12 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 13 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 14 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 15 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 16 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 17 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 18 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 19 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 20 | WLR | WHR | WHR | WHR | WHR | WHR | WHR | WLR |
| 21 | WLR | WMR | WMR | WMR | WMR | WMR | WMR | WLR |
| 22 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 23 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |
| 24 | WLR | WLR | WLR | WLR | WLR | WLR | WLR | WLR |

WLR—Winter Low-Risk
WMR—Winter Medium-Risk
WHR—Winter High-Risk

## *Off-Season Risk Hours (March 1–May 31, September 16–October 31)*

| Hour End | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 2 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 3 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 4 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 5 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 6 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 7 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 8 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 9 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 10 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 11 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 12 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 13 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 14 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 15 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 16 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 17 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 18 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 19 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 20 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 21 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 22 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 23 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |
| 24 | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR | OFLR |

OFLR —Off-Season Low-Risk

While the identified seasons and hours capture over 95% of the total hourly risk, the magnitude of LOLP values vary. Planning to the 0.1 event-days per year LOLE threshold, the percentage of risk distribution can be visualized through the lens of the monthly LOLE results, as shown in the following table.

| Month | LOLE Percentage |
|---|---|
| Jan | *0.6% |
| Feb | *0.0% |
| Mar | 0.0% |
| Apr | 0.0% |
| May | 0.0% |
| Jun | 2.8% |
| Jul | 58.5% |
| Aug | 19.3% |
| Sep | 3.6% |
| Oct | 1.0% |
| Nov | 6.7% |
| Dec | 7.4% |
| Total | 100.0% |

*January and February are expected to be as high as November and Decemberf for the 2025–2026 winter season due to forecasted industrial customer load ramps.

# 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 solar), 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*.

The after-tax marginal WACC rate used to discount all future resource costs is discussed in Appendix C: 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. Plant forced outages are modeled in RCAT on a unit basis and are discussed in *Appendix C: Technical Appendix Loss of Load Expectation*. Risk and uncertainty associated with fuel prices and greenhouse gas emissions are discussed in *Chapter 9 Portfolios*. The AURORA generated electricity prices are impacted by the above assumptions and are considered in the analysis.

Additional sources of risk and uncertainty including qualitative risks are discussed in *Chapter 10. Modeling Analysis*.

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.
   - Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.
   - To address risk, the plan should include, at a minimum:
     a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
     b. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.
   - The utility should explain in its plan how its resource choices appropriately balance cost and risk.

**Idaho Power response:**

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. 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*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 10. Modeling Analysis*.

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. Clean Energy & 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 *Appendix C: 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:**

Prior to filing, Idaho Power posted online a draft 2023 IRP Report for public review and comment in September 2023..

## 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 2021 IRP on December 6, 2022, in Order 23-004. Filing the 2023 IRP in September 2023 complies with the requirement to file the company's next IRP within two years of acknowledgement of the prior IRP.

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 work with Commission Staff and other interested parties to set a schedule for review of the 2023 IRP, including a public meeting with the Commission following the September 2023 filing.

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 will file an annual update of the 2023 IRP, assuming the annual update will occur more than six months before filing the 2025 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 *Chapter 10. Modeling Analysis.*

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 expected for existing resources are modeled in AURORA. Identification of capacity and energy needed to bridge the gap between expected loads and resources is an output of AURORA LTCE modeling; results of which are found in *Appendix C: Technical Appendix*. All existing transmission rights and future transmission additions are modeled in AURORA.

Detailed forecasts are provided in *Appendix C: Technical Appendix*, *Sales and Load Forecast Data* and *Existing Resource Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 11. Preferred Portfolio and Action Plan*.

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 baseload), transportation and storage needed to bridge the gap between expected loads and resources;

**Idaho Power response:**

Not applicable to Idaho Power.

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 *Appendix C: Technical Appendix, Supply-Side Resource Data*.

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.*

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 *Appendix C: Technical Appendix, Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in *Chapter 10. Modeling Analysis*.

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 2023 IRP are described in *Chapter 9. Portfolios* and *Appendix C: Technical Appendix*, *Long-Term Capacity Expansion Results*.

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*.

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.*

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*.

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 Portfolio is identified in *Chapter 11. Preferred Portfolio and Action Plan* and represents the best combination of cost and risk.

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:**
The company has identified that its plans are consistent with all state and federal energy policies as of the time of filing.

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:**
All identified requirements in Guideline 5: Transmission are met and modeled in AURORA. Transmission assumptions for supply-side resources and market access 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 2023 IRP is described in *Chapter 6. Demand-Side Resources* and is included as *Appendix B: DSM Annual Report*.

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 recast for energy efficiency is provided in Cha*pter 6. Demand-Side Resources*. The load forecast put into AURORA included the reduction to customer sales of all future achievable economic energy efficiency potential.

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. Third-party market transformation savings are provided by the Northwest Energy Efficiency Alliance (NEEA) and are 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:**

Idaho Power's examination of the potential for expanded DR resources is presented in *Chapter 6. Demand-Side Resources*.

## 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 2023 IRP are found in *Chapter 9. Portfolios*. Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 10. Modeling Analysis*. Emissions for each portfolio are shown in *Appendix C: Technical Appendix*, *Portfolio Emissions Forecast*.

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* for discussion on the various scenarios and comparative analysis of the scenarios. Economic lives were adjusted based on portfolio conditions.

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* 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 *Appendix C: Technical Appendix, Long-Term Capacity Expansion Results*..

## 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 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*. Idaho Power will file the 2023 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 to determine the company's annual capacity positions is discussed in *Chapter 10. Modeling Analysis* and Appendix C: Technical Appendix, *Loss of Load Expectation.*

## 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:**

Distribution-connected storage 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 follows an all-source RFP process where possible to acquire resources which may or may not be owned by the company and are evaluated to provide maximum benefit to its customers.

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 to Idaho Power.

# 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 Idaho Power'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 capacity planning reserve 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*. Demand response storage-related programs, like EVs could provide, were modeled; this is discussed in *Chapter 6. Demand-Side Resources*.

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2021 IRP

## Action Item 1: B2H

Conduct ongoing Boardman to Hemingway (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.

**Idaho Power response:**

Discussions of Idaho Power's B2H permitting activities, partner construction agreements, and CPCN filings are included in *Chapter 7: Transmission Planning.*

## Action Item 2: SWIP–North

Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs with the condition that Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.

**Idaho Power response:**

Opportunities related to SWIP-North are discussed in *Chapter 7: Transmission Planning.* Idaho Power also discusses SWIP-North and its impact on congestion and southern market opportunity in *Chapter 7: Transmission Planning.*

## Action Item 3: Jackpot Solar

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.

**Idaho Power response:**

Not applicable. Jackpot Solar began commercial operations in December 2022, as scheduled.

## Action Item 4: Jim Bridger Units 1 and 2

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.

**Idaho Power response:**

In *Chapter 5: Future Supply-Side Generation and Storage Resources*, Idaho Power discusses its plans with PacifiCorp to convert Bridger Units 1 and 2 to natural gas operation in 2024. Coordination with PacifiCorp has led to a scheduled exit date of 2037 for Bridger Units 1 and 2.

## Action Item 5: 2024 and 2025 RFP

Issue a Request for Proposal ("RFP") to procure resources to meet identified deficits in 2024 and 2025.

**Idaho Power response:**

Idaho Power completed an RFP process to meet the deficits identified in 2024 and 2025.

## Action Item 6: Jim Bridger Units 3 and 4

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.

**Idaho Power response:**

In *Chapter 5: Future Supply-Side Generation and Storage Resources*, Idaho Power discusses updates to its plans with PacifiCorp regarding Bridger Units 3 and 4 conversion/exit dates.

## Action Item 7: Demand Response

Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.

**Idaho Power response:**

Idaho Power discusses its existing DR programs in *Chapter 6: Demand-Side Resources.* The amount of additional DR necessary to meet the identified need is included in *Chapter 11: Preferred Portfolio and Action Plan.*

## Action Item 8: B2H

Conduct preliminary construction activities, acquire long lead materials, and construct the B2H project.

**Idaho Power response:**

Updates regarding B2H construction activities are included in *Chapter 7: Transmission Planning.*

## Action Item 9: Energy Efficiency

Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.

**Idaho Power response:**

Idaho Power's implementation of cost-effective energy efficiency measures is discussed in *Chapter 6: Demand-Side Resources*.

## Action Item 10: Large-Load Customers

Work with large-load customers to support their energy needs with solar resources.

**Idaho Power response:**

Idaho Power's Clean Energy Your Way–Construction program supports Idaho-based large-load customers' energy needs with renewable resources, including solar. The program is described in more detail in *Chapter 3: Clean Energy & Climate Change*. Examples of Clean Energy Your Way–Construction projects are included in *Chapter 4: Idaho Power Today*.

## Action Item 11: Storage Projects

Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.

**Idaho Power response:**

The implementation of four distribution-connected storage projects is discussed in *Chapter 5: Future Supply-Side Generation and Storage Resources.* The four projects are expected to be online in fall of 2023, and are located at Filer, Weiser, Melba, and Elmore substations.

## Action Item 12: Valmy Unit 2

Exit Valmy unit 2 by December 31, 2025.

**Idaho Power response:**

The *Executive Summary* discusses Idaho Power's updated plans regarding Valmy Unit 2 exit/conversion.

## Action Item 13: Jim Bridger Unit 3

Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

**Idaho Power response:**

Idaho Power describes its updated plan with PacifiCorp regarding Bridger Unit 3 exit/conversion date in the *Executive Summary*.

## Additional Recommendation 1: B2H

Direct Idaho Power to produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions.

**Idaho Power response:**

B2H cost estimates were updated as of September 2023 and are included in *Chapter 7: Transmission Planning*. B2H-related swaps and investments, breaking the total down by component, and disclosing all data and assumptions for each estimated component cost were provided in OPUC Docket No. PCN 5 to support procurement actions.

## Additional Recommendation 2: Wholesale Prices

Direct Idaho Power to work with stakeholders and demonstrate the impact of extremely high wholesale electricity prices and decreased liquidity on resource selection in the 2023 IRP. In addition, Idaho Power shall provide insight into volatility and need.

**Idaho Power response:**

Idaho Power worked with members of IRPAC to change its stochastic analysis to help incorporate a greater range of wholesale electricity prices derived from modeled periods of decreased liquidity in wholesale markets. The changes to the stochastic analysis generated a wide range of electricity prices and their influence on portfolio cost can be found in Appendix C: Technical Appendix, *Stochastic Risk Analysis.*

## Additional Recommendation 3: Grant Opportunities

Direct Idaho Power to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including the items bulleted in Staff's Report.

**Idaho Power response:**

The monitoring and pursuit of Idaho Power's grant opportunities are discussed in *Chapter 7: Transmission Planning.*

## Additional Recommendation 4: Demand Response

Direct Idaho Power to model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.

**Idaho Power response:**

Idaho Power completed the potential study and modeled new and expanded DR in the 2023 IRP; DR resource potential is discussed in *Chapter 6: Demand-Side Resources.*

## Additional Recommendation 5: Large-Load Customers

For all clean energy special contracts with large load customers, direct Idaho power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan in a manner that does not compromise Idaho Power or customer confidentiality.

**Idaho Power response:**

Clean Energy Your Way special contract timing needs are included in the Action Plan and can be found in the *Executive Summary*. Additionally, existing Clean Energy Your Way–Construction projects are discussed in *Chapter 3: Clean Energy & Climate Change.*

## Additional Recommendation 6: WRAP

Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions and implications for capacity contracts.

**Idaho Power response:**

Idaho Power provides a brief overview of WRAP in *Chapter 2: Political, Regulatory, and Operational Considerations.* Additionally, WRAP modeling assumptions are discussed in this appendix. As WRAP operations continue to mature, Idaho Power will monitor how participating in WRAP may alter planning assumptions.

## Additional Recommendation 7: Reliability

Direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard.

**Idaho Power response:**

All main cases in the 2023 IRP include the resources necessary to produce an annual capacity position of surplus (to meet Idaho Power's 0.1 event-day/year LOLE threshold).

## Additional Recommendation 8: QF Renewal Rate

Direct Idaho Power to revisit the assumed renewal rate of wind QFs.

**Idaho Power response:**

Idaho Power addresses the assumed renewal rates of wind QFs in *Chapter 9: Portfolios.* Idaho Power and IRPAC revisited the wind QF renewal rates, and the company conducted the New Forecasted PURPA scenario based on their input.

## Additional Recommendation 9: QF Forecast

Direct Idaho Power to work with Staff and stakeholders to develop a reasonable forecast of new QFs in the 2023 IRP.

**Idaho Power response:**

Idaho Power addresses the QF forecast in *Chapter 9: Portfolios.* Idaho Power worked with IRPAC to add a QF forecast, and the company conducted the New Forecasted PURPA scenario based on their input.

## Additional Recommendation 10: GHG Emissions

Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in a reasonably similar method. The data should include emissions from market purchases and remove emissions from market sales.

**Idaho Power response:**

Idaho Power included a GHG historical/forecast comparison graph in the *Executive Summary*.

## Additional Recommendation 11: Green Hydrogen Proxy

Direct Idaho Power to include the most reasonable proxy of green hydrogen as a potential resource in its next IRP, either available for selection in a portfolio or in a sensitivity.

**Idaho Power response:**

Idaho Power modeled green hydrogen resources in portfolios and sensitivities for the 2023 IRP.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 84

IDAHO POWER COMPANY

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**Attachment 2**

IRP Commitments

September 29, 2023

| Idaho | | | |
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| **Reference** | **Topic** | **IRP Requirement, Recommendation or Commitment** | **How the Item is Addressed in the 2023 IRP** |
| Order No. 35603, p. 4 | Jim Bridger Units | Develop a Bridger exit agreement with PacifiCorp that determines potential costs of extending or exiting operations early similar to the exit agreement developed for the closure of Valmy and incorporate those costs into its coal plant exit costs to properly value different exit dates in its 2023 IRP. | In *Chapter 5: Future Supply-Side Generation and Storage Resources*, Idaho Power discusses its plans with PacifiCorp to convert Bridger Units 1 and 2 to natural gas operation in 2024. Coordination with PacifiCorp has led to a scheduled exit date of 2037 for Bridger Units 1 and 2. Additionally, Idaho Power discusses updates to its plans with PacifiCorp regarding Bridger Units 3 and 4 conversion/exit dates. |
| Order No. 35603, p. 4 | Extreme Weather | Incorporate extreme weather events and variability of water availability through its load and resource input assumptions, rather than compensating by changing the LOLE reliability target, which should be set as a matter of public policy. | In *Chapter 8: Planning Period Forecasts*, Idaho Power discusses its 70$^{th}$ percentile load forecast and how it accounts for load variability due to weather events. A more detailed discussion of Idaho Power's weather-based probabilistic scenarios and seasonal peaks is included in *Appendix A—Sales and Load Forecast*. In the Loss of Load Expectation section of *Appendix C—Technical Report*, Idaho Power also discusses its utilization of a 0.1 event-days per year LOLE threshold for the 2023 IRP. |
| Order No. 35603, p. 4 | Market Access | Only include market access backed by firm transmission reservations in its Load and Resource Balance. | In the Existing Transmission Capacity for Firm Market Imports section of *Chapter 7: Transmission Planning*, Idaho Power describes the existing transmission modeled in the 2023 IRP that provides transmission capacity for firm market imports. |
| Order No. 35603, p. 4 | PRM | Evaluate the risks and inaccuracies caused by using a single benchmark year (2023) to determine the LOLE-based Planning Reserve Margin. | In the Capacity Planning Reserve Margin section of *Chapter 9: Portfolios*, Idaho Power explains the implementation of LOLE-based seasonal Planning Reserve Margin calculations performed at different points along the planning horizon for utilization in the AURORA LTCE model. Additional information regarding the LOLE methodology can be found in the Loss of Load Expectation section of *Appendix C—Technical Report*. |
| Order No. 35603, p. 4 | Validation and Verification | Provide a comprehensive Quality Assurance plan to verify and validate its models by describing the purpose of each test, how the test was conducted, and the result. | Idaho Power provides details regarding its verification tests and overall validation and verification process in *Chapter 9: Portfolios* with resource buildouts located in *Appendix C—Technical Report.* Additionally, in *Chapter 10: Modeling Analysis*, Idaho Power provides a qualitative risk analysis and comparison for different portfolio buildouts analyzed in the 2023 IRP. |
| Order No. 35603, p. 4 | Flexible Resource Strategy | Study the costs and benefits of implementing a flexible resource strategy. | In *Chapter 11: Preferred Portfolio and Near-Term Action Plan*, Idaho Power describes the flexible resource strategy identified in the Preferred Portfolio and compares the costs and benefits of the Preferred Portfolio to varying future scenarios analyzed in the 2023 IRP. |

| Oregon | | | |
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| **Reference** | **Topic** | **IRP Requirement, Recommendation or Commitment** | **How the Item is Addressed in the 2023 IRP** |
| Order No. 23-004, Appendix A, p. 8 | Jim Bridger Units 1 and 2 | 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. | In *Chapter 5: Future Supply-Side Generation and Storage Resources*, Idaho Power discusses its plans with PacifiCorp to convert Bridger Units 1 and 2 to natural gas operation in 2024. Coordination with PacifiCorp has led to a scheduled exit date of 2037 for Bridger Units 1 and 2. |
| Order No. 23-004, Appendix A, p. 8 | Jim Bridger Units 3 and 4 | 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. | In *Chapter 5: Future Supply-Side Generation and Storage Resources*, Idaho Power discusses updates to its plans with PacifiCorp regarding Bridger Units 3 and 4 conversion/exit dates. |
| Order No. 23-004, Appendix A, p. 8 | Jim Bridger Unit 3 | Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025. | Idaho Power describes its updated plan with PacifiCorp regarding Bridger Unit 3 exit/conversion date in the *Executive Summary*. |
| Order No. 23-004, Appendix A, p. 10 | SWIP-North | Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs with the condition that Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets. | Opportunities related to SWIP-North are discussed in *Chapter 7: Transmission Planning.* Idaho Power also discusses SWIP-North and its impact on congestion and southern market opportunity in *Chapter 7: Transmission Planning.* |
| Order No. 23-004, Appendix A, p. 19 and Idaho Power's Reply Comments, p. 5 | B2H | Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Conduct ongoing activities related to petitions for a certificate of public convenience and necessity with state commissions. | Discussions of Idaho Power's B2H permitting activities, partner construction agreements, and CPCN filings are included in *Chapter 7: Transmission Planning.* |
| Order No. 23-004, Appendix A, p. 19 | B2H | Conduct preliminary construction activities, acquire long lead materials, and construct the B2H project. | Updates regarding B2H construction activities are included in *Chapter 7: Transmission Planning.* |
| Order No. 23-004, Appendix A, p. 19 | B2H | Direct Idaho Power to produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions. | B2H cost estimates were updated as of September 2023 and are included in *Chapter 7: Transmission Planning*. B2H-related swaps and investments, breaking the total down by component, and disclosing all data and assumptions for each estimated component cost were provided in OPUC Docket No. PCN 5 to support procurement actions. |
| Order No. 23-004, Appendix A, p. 19 | Wholesale Prices | Direct Idaho Power to work with stakeholders and demonstrate the impact of extremely high wholesale electricity prices and decreased liquidity on resource selection in the 2023 IRP. In addition, Idaho Power shall provide insight into volatility and need. | Idaho Power worked with members of IRPAC to change its stochastic analysis to help incorporate a greater range of wholesale electricity prices derived from modeled periods of decreased liquidity in wholesale markets. The changes to the stochastic analysis generated a wide range of electricity prices and their influence on portfolio cost can be found in Appendix C: Technical Appendix, *Stochastic Risk Analysis.* |
| Order No. 23-004, Appendix A, p. 19 | Grant Opportunities | Direct Idaho Power to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including the items bulleted in Staff's Report. | The monitoring and pursuit of Idaho Power's grant opportunities are discussed in *Chapter 7: Transmission Planning.* |

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| Order No. 23-004, Appendix A, p. 20 | 2024 and 2025 RFP | Issue a Request for Proposal ("RFP") to procure resources to meet identified deficits in 2024 and 2025. | Idaho Power completed an RFP process to meet the deficits identified in 2024 and 2025. |
| Order No. 23-004, Appendix A, p. 23 | Demand Response | Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need. | Idaho Power discusses its existing DR programs in *Chapter 6: Demand-Side Resources.* The amount of additional DR necessary to meet the identified need is included in *Chapter 11: Preferred Portfolio and Near-Term Action Plan.* |
| Order No. 23-004, Appendix A, p. 23 | Energy Efficiency | Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment. | Idaho Power's implementation of cost-effective energy efficiency measures is discussed in *Chapter 6: Demand-Side Resources*. |
| Order No. 23-004, Appendix A, p. 23 | Demand Response | Direct Idaho Power to model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs. | Idaho Power completed the potential study and modeled both the potential of existing programs and identified new programs in the 2023 IRP; DR resource potential is discussed in *Chapter 6: Demand-Side Resources.* |
| Order No. 23-004, Appendix A, p. 24 | Large-Load Customers | Work with large-load customers to support their energy needs with solar resources. | Idaho Power's Clean Energy Your Way – Construction program supports Idaho-based large-load customers' energy needs with renewable resources, including solar. The program is described in more detail in *Chapter 3: Clean Energy & Climate Change.* Examples of Clean Energy Your Way – Construction projects are included in *Chapter 4: Idaho Power Today.* |
| Order No. 23-004, Appendix A, p. 24 and Idaho Power's Reply Comments, p. 10 | Large-Load Customers | For all clean energy special contracts with large load customers, direct Idaho power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan in a manner that does not compromise Idaho Power or customer confidentiality. | Clean Energy Your Way special contract timing needs are included in the Action Plan and can be found in the *Executive Summary.* Additionally, existing Clean Energy Your Way – Construction projects are discussed in *Chapter 3: Clean Energy & Climate Change.* |
| Order No. 23-004, Appendix A, p. 25 | Valmy Unit 2 | Exit Valmy unit 2 by December 31, 2025. | The *Executive Summary* discusses Idaho Power's updated plans regarding Valmy Unit 2 exit/conversion. |
| Order No. 23-004, Appendix A, p. 26 | Jackpot Solar | 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. | Not applicable. Jackpot Solar began commercial operations in December 2022, as scheduled. |
| Order No. 23-004, Appendix A, p. 27 | Storage Projects | Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan. | The implementation of four distribution-connected storage projects is discussed in *Chapter 5: Future Supply-Side Generation and Storage Resources.* The four projects are expected to be online in fall of 2023, and are located at Filer, Weiser, Melba, and Elmore substations. |
| Order No. 23-004, Appendix A, p. 28 | WRAP | Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions and implications for capacity contracts. | Idaho Power provides a brief overview of WRAP in *Chapter 2: Political, Regulatory, and Operational Considerations.* Additionally, WRAP modeling assumptions are discussed in this appendix. As WRAP operations continue to mature, Idaho Power will monitor how participating in WRAP may alter planning assumptions. |
| Order No. 23-004, Appendix A, p. 35 | Reliability | Direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard. | All main cases in the 2023 IRP include the resources necessary to produce an annual capacity position of surplus (to meet Idaho Power's 0.1 event-day/year LOLE threshold). |

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| Order No. 23-004, Appendix A, p. 37 | QF Renewal Rate | Direct Idaho Power to revisit the assumed renewal rate of wind QFs. | Idaho Power addresses the assumed renewal rates of wind QFs in *Chapter 9: Portfolios.* Idaho Power and IRPAC revisited the wind QF renewal rates, and the company conducted the New Forecasted PURPA scenario based on the IRPAC's input. |
| Order No. 23-004, Appendix A, p. 37 and Idaho Power's Reply Comments, p. 12 | QF Forecast | Direct Idaho Power to work with Staff and stakeholders to develop a reasonable forecast of new QFs in the 2023 IRP. | Idaho Power addresses the QF forecast in *Chapter 9: Portfolios.* Idaho Power worked with IRPAC to add a QF forecast, and the company conducted the New Forecasted PURPA scenario based on their input. |
| Order No. 23-004, Appendix A, p. 38 and Idaho Power's Reply Comments, p. 14 | GHG Emissions | Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in a reasonably similar method. The data should include emissions from market purchases and remove emissions from market sales. | Idaho Power included a GHG historical/forecast comparison graph in the *Executive Summary*. |
| Order No. 23-004, Appendix A, p. 39 | Green Hydrogen Proxy | Direct Idaho Power to include the most reasonable proxy of green hydrogen as a potential resource in its next IRP, either available for selection in a portfolio or in a sensitivity. | Idaho Power modeled green hydrogen resources in portfolios and sensitivities for the 2023 IRP. |