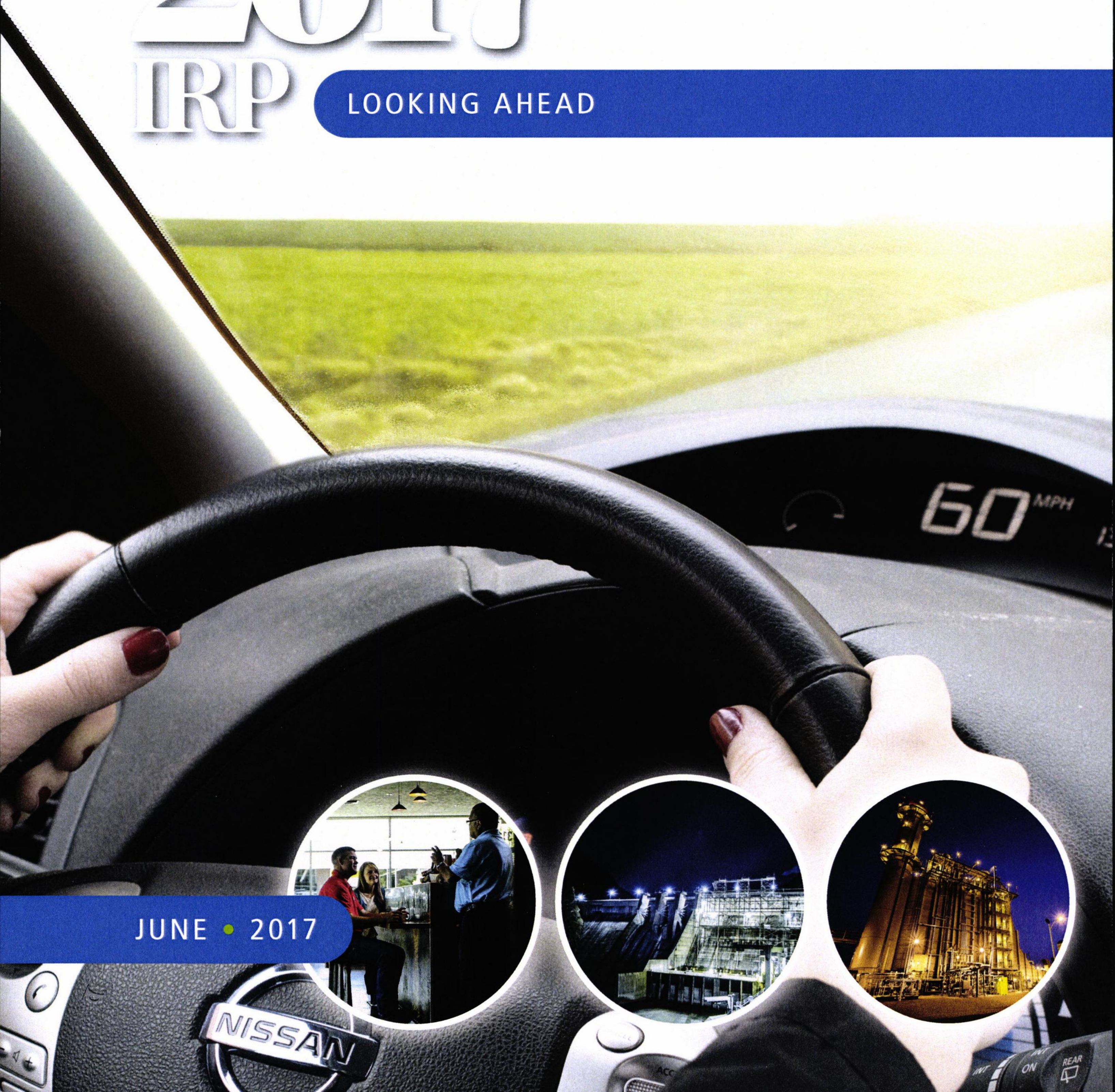
INTEGRATED RESOURCE PLAN

IDAHO POWER®
An IDACORP Company

2017 IRP

LOOKING AHEAD



JUNE • 2017

SAFE HARBOR STATEMENT

INTEGRATED RESOURCE PLAN

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LOOKING FORWARD

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2017 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public-interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at idahopower.com.

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Glossary of Acronyms

A/C—Air Conditioning
AC—Alternating Current
AEG—Applied Energy Group
AEO—Annual Energy Outlook
AFUDC—Allowance for Funds Used During Construction
AgI—Silver Iodide
akW—Average Kilowatt
aMW—Average Megawatt
ATC—Available Transmission Capacity
B2H—Boardman to Hemingway
BLM—Bureau of Land Management
BPA—Bonneville Power Administration
BSER—Best System of Emissions Reduction
CAA—*Clean Air Act of 1970*
CAISO—California Independent System Operator
CAMP—Comprehensive Aquifer Management Plan
CCCT—Combined-Cycle Combustion Turbine
cfs—Cubic Feet per Second
CHP—Combined Heat and Power
CHQ—Corporate headquarters
Clatskanie PUD—Clatskanie People's Utility District
CO_2—Carbon Dioxide
COE—United States Army Corps of Engineers
CREP—Conservation Reserve Enhancement Program
CSPP—Cogeneration and Small-Power Producers
CWA—*Clean Water Act of 1972*
D.C.—District of Columbia
DC—Direct Current
DER—Distributed Energy Resources
DOE—Department of Energy
DSM—Demand Side Management
EEAG—Energy Efficiency Advisory Group
EGU—Electric Generating Unit
EIA—Energy Information Administration
EIM—Energy Imbalance Market
EIS—Environmental Impact Statement
EPA—Environmental Protection Agency
ESA—*Endangered Species Act of 1973*

ESPA—Eastern Snake River Plain Aquifer
ESPAM—Enhanced Snake River Plain Aquifer Model
F—Fahrenheit
FCRPS—Federal Columbia River Power System
FERC—Federal Energy Regulatory Commission
FPA—*Federal Power Act of 1920*
FWS—US Fish and Wildlife Service
GWh—Gigawatt-Hour
GWMA—Ground Water Management Area
HCC—Hells Canyon Complex
HRSG—Heat Recovery Steam Generator
IDWR—Idaho Department of Water Resources
IGCC—Integrated Gasification Combined Cycle
INL—Idaho National Laboratory
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
IWRB—Idaho Water Resource Board
kV—Kilovolt
kW—Kilowatt
kWh—Kilowatt-Hour
LCOC—Levelized Cost of Capacity
LCOE—Levelized Cost of Energy
LiDAR—Light Detection and Ranging
LOLE—Loss-of-Load Expectation
LOLP—Loss-of-Load Probability
LTP—Local Transmission Plan
m2—Square Meters
MATL—Montana–Alberta Tie Line
MOU—Memorandum of Understanding
MSA—Metropolitan Statistical Area
MW—Megawatt
MWh—Megawatt-Hour
NEEA—Northwest Energy Efficiency Alliance
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NOx—Nitrogen Oxide
NPV—Net Present Value
NREL—National Renewable Energy Laboratory
NTTG—Northern Tier Transmission Group

NWPCC—Northwest Power and Conservation Council
NWPP—Northwest Power Pool
O&M—Operation and Maintenance
OATT—Open Access Transmission Tariff
ODEQ—Oregon Department of Environmental Quality
ODOE—Oregon Department of Energy
OEMR—Office of Energy and Mineral Resources
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statue
pASC—Preliminary Application for Site Certificate
PCA—Power Cost Adjustment
PGE—Portland General Electric
PM&E—Protection, Mitigation, and Enhancement
PPA—Power Purchase Agreement
PURPA—*Public Utility Regulatory Policies Act of 1978*
PV—Photovoltaic
QA—Quality Assurance
QF—Qualifying Facility
RAAC—Resource Adequacy Advisory Committee
REC—Renewable Energy Certificate
RFP—Request for Proposal
RH BART—Regional Haze Best Available Retrofit Technology
ROD—Record of Decision
ROI—Return on Investment
ROR—Run-of-River
ROW—Right-of-Way
RPS—Renewable Portfolio Standard
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SIP—State Implementation Plan
SMR—Small Modular Reactor
SO_2—Sulfur Dioxide
SRBA—Snake River Basin Adjudication
SRPM—Snake River Planning Model
T&D—Transmission and Distribution
TEPPC—Transmission Expansion Planning Policy Committee
TES—Thermal Energy Storage
TRC—Total Resource Cost
UAMPS—Utah Associated Municipal Power Systems
US—United States
USBR—Bureau of Reclamation
USFS—United States Forest Service

VRB—Vanadium Redox-Flow Battery
WDEQ—Wyoming Department of Environmental Quality
WECC—Western Electricity Coordinating Council

1. SUMMARY

Introduction

The *2017 Integrated Resource Plan* (IRP) is Idaho Power's 13th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). Idaho Power's resource planning process has four primary goals:

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

The 2017 IRP evaluates the 20-year planning period from 2017 through 2036. During this period, load is forecasted to grow by 0.9 percent per year for average energy demand and 1.4 percent per year for peak-hour demand. Total customers are expected to increase to 756,000 by 2036 from 534,000 in 2016. Additional company-owned resources will be needed to meet these increased demands.[1]

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Hydroelectric generation is a large part of Idaho Power's generation fleet; however, hydroelectric plants are subject to variable water and weather conditions. Public and regulatory input encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP. In response to this input, Idaho Power continues to develop more conservative streamflow projections and planning criteria for use in resource adequacy planning. Idaho Power has an obligation to serve customer loads regardless of water and weather conditions. Further discussion of Idaho Power's IRP planning criteria can be found in Chapter 7.

[1] Recent company disclosures forecast load growth during the 2016 to 2035 planning period at 1 percent for average energy demand and 1.4 percent for peak-hour demand.

Other resources relied on for planning include demand-side management (DSM) and transmission resources. The goal of DSM programs is to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response programs. Idaho Power also strives to provide customers with tools and information to help them manage their own energy usage. The company achieves these objectives through the implementation and careful management of incentive programs and through outreach and education.

Idaho Power's resource planning process also includes evaluating additional transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and their planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG). Idaho Power coordinates local transmission planning with regional forums, as well as the Federal Energy Regulatory Commission (FERC). Idaho Power is obligated under 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[2] and Idaho Power retail customers.[3] The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

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

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

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

Public Advisory Process

IRPAC meeting, May 2017

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council (IRPAC). The IRPAC meets most months during the development of the resource plan, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2017 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2017 IRP, Idaho Power conducted eight IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment.

Idaho Power believes working with members of the IRPAC and the public improves the IRP. Idaho Power and the members of the IRPAC recognize that final decisions on the resource plan are made by Idaho Power. However, Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2017 IRP and the resource planning process in general.

IRP Methodology

A primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand over the 20-year planning period. A tool critical to assessing resource sufficiency is the load and resource balance, which compares projected customer demand with system resources available for meeting demand. An effective IRP methodology identifies deficiencies in the 20-year load and resource balance and analyzes options for satisfying the identified resource deficiencies. The practical implication of successful integrated resource planning is that system operators of the future are equipped with a system having sufficient resources to maintain reliable electrical service to Idaho Power's customers.

Resource sufficiency is assessed for energy and capacity. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand response resources are included in the capacity resource sufficiency assessment as well. Idaho Power then includes the IRP target amount of cost-effective and achievable energy efficiency, which reflects expansion of existing energy-savings potential.

Based on identified resource deficiencies over the planning period, Idaho Power conducts a financial analysis of various resources and all portfolios to quantitatively evaluate the individual resources and resulting portfolios designed to remediate any energy or capacity deficiency over the planning period. Within the financial analysis, Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), transmission upgrades associated with interconnecting new resource options, and anticipated environmental controls. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy certificates (REC) for REC-eligible resources.

The Idaho Power balancing area is part of the larger western interconnect. Idaho Power must balance loads and generation per North American Electric Reliability Corporation (NERC) system reliability standards. During times of acute oversupply, Idaho Power must rely on available system resources to regain intra-hour balance and must sometimes curtail intermittent resources like wind and solar. Power markets are available via transmission lines to purchase or sell power inter-hour to balance the system.

An additional transmission connection to the Pacific Northwest has been part of Idaho Power's preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line, and since 2009 the addition has been called the Boardman to Hemingway (B2H) Transmission Line Project. Idaho Power again evaluated the B2H transmission line in the 2017 IRP to ensure the transmission addition remains a prudent resource acquisition.

Greenhouse Gas Emissions

Idaho Power's carbon dioxide (CO_2) emission levels have historically been well below the national average for the 100 largest electric utilities in the United States (US), both in terms of CO_2 emissions intensity (pounds per megawatt-hour [MWh] generation) and total CO_2 emissions (tons) (Figure 1.1 and Figure 1.2).

Figure 1.1 Estimated Idaho Power CO_2 emissions intensity

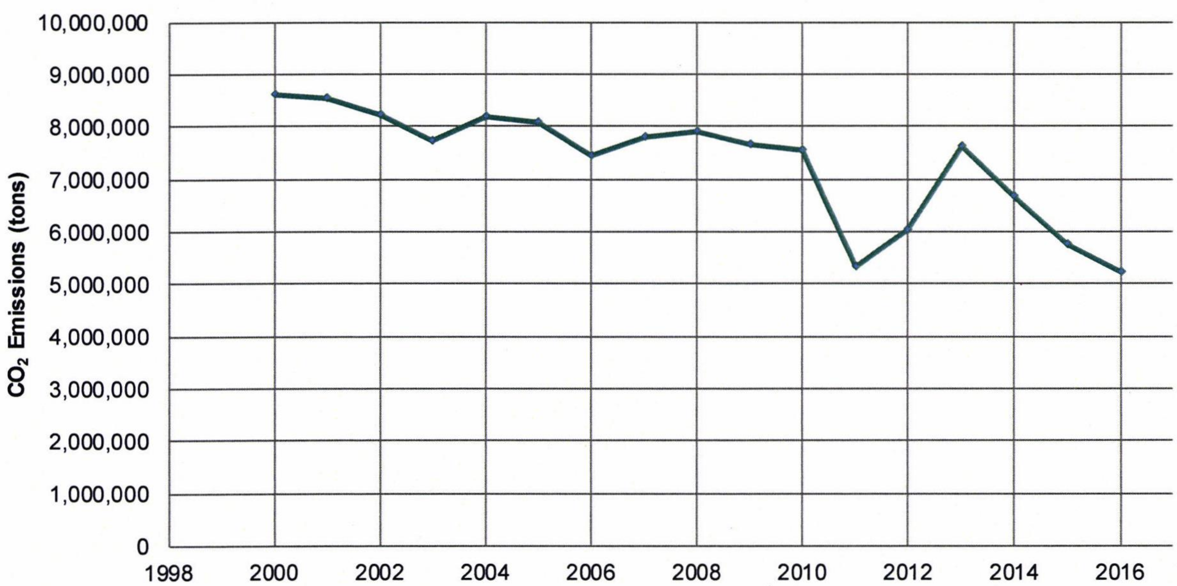

Figure 1.2 Estimated Idaho Power CO_2 emissions

In September 2009, Idaho Power's Board of Directors approved guidelines to reduce Idaho Power's resource portfolio average CO_2 emissions intensity from 2010 through 2013 to 10 to 15 percent below the company's 2005 CO_2 emissions intensity of 1,194 pounds per MWh. Because Idaho Power's CO_2 emissions intensity fluctuates with streamflows and production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

Generation and emissions from company-owned resources are included in the CO_2 emissions intensity calculation. The company'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.[4] Information related to Idaho Power's CO_2 emissions, voluntarily reported annually, is also available through the Carbon Disclosure Project at cdp.net.

In November 2012, the Board of Directors approved an extension of the company's 2010 to 2013 goal for reducing CO_2 emissions intensity. The goal as restated in 2012 was to achieve a CO_2 emissions intensity 10 to 15 percent below the 2005 CO_2 emissions intensity from 2010 to 2015. That goal was met.

In May 2017, the Board of Directors approved the current CO_2 emissions intensity goal, which extends the target CO_2 emissions intensity of 15 to 20 percent below the 2005 CO_2 emissions intensity through 2020. As of the end of 2016, the company's CO_2 emissions intensity was 858 pounds per MWh, 28 percent below the 2005 CO_2 emissions intensity.

The portfolio analysis performed for the 2017 IRP assumes all resource portfolios comply with state-by-state mass-based emission limits detailed in the Clean Power Plan Final Rule filed in the Federal Register in October 2015. Further discussion of these CO_2 emission constraints is provided in Chapter 9. Projected CO_2 emissions for each analyzed resource portfolio are provided in *Appendix C—Technical Appendix*.

Portfolio Analysis Summary

Idaho Power designed the portfolio analysis for the 2017 IRP to inform the IRP's action plan with respect to two key resource actions: 1) selective catalytic reduction (SCR) investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively, and 2) the B2H transmission line. To achieve this objective, portfolios were formulated such that the effects of these two resource actions, or factors, could be isolated. This portfolio design approximates a controlled experiment using a factorial experimental design. This design is an effective statistical technique for studying differences between two (or more) factors, each factor having more than one possible level. An outline of the factorial design specifically in the context of the 2017 IRP is as follows:

- **Factor 1:** Treatment of Jim Bridger units 1 and 2
    - Level 1: Invest in SCRs and operate through 2036
    - Level 2: Retire Unit 1 in 2028 and Unit 2 in 2024 (without investing in SCRs)
    - Level 3: Retire Unit 1 in 2032 and Unit 2 in 2028 (without investing in SCRs)
    - Level 4: Retire Unit 1 in 2022 and Unit 2 in 2021 (without investing in SCRs)

[4] idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm

- **Factor 2:** Primary portfolio element(s)
  - Level 1: B2H
  - Level 2: Solar PV/natural gas-fired generation
  - Level 3: Natural gas-fired generation

Table 1.1 provides a matrix of the factorial design with the portfolios corresponding to each factorial combination.

Table 1.1 Factorial design applied to portfolios

	Primary Portfolio Element(s)		
Treatment of Jim Bridger Units 1 and 2	**B2H**	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

The IRP emphasizes that the validity of the factorial design relies on by-column and by-row uniformity; that is, all portfolios within a given row in the above table must uniformly reflect the same SCR investment scenario, and similarly all portfolios within a given column must uniformly reflect the same primary portfolio element(s). This uniformity is critical to yielding meaningful inferences from the factorial design.

The 12 resource portfolios formulated were analyzed under planning-case conditions for natural gas price, hydroelectric production, and system load. The analysis also included a range of eight natural gas sensitivities and a stochastic risk analysis. The stochastic risk analysis modeled 100 iterations (or futures) on the selected stochastic risk variables: natural gas price, hydroelectric production, and system load. These analyses are described in more detail in Chapter 9. The top performing portfolio from the quantitative portfolio analysis is portfolio 7 (P7). Table 1.1 demonstrates P7 is a portfolio with B2H as the primary element and assumes retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively. The resource additions with dates for P7 are provided in Table 1.2.

Table 1.2 P7 resource additions

Date	Resource	Installed Capacity
2026	B2H	500 megawatts (MW) transfer capacity Apr–Sep, 200 MW transfer capacity Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	Combined-cycle combustion turbine (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

The qualitative risk analysis supports the selection of P7, finding that P7 does not carry greater exposure to qualitative risk factors than other portfolios. In fact, P7 has unique qualitative benefits associated with Idaho Power's participation in an energy imbalance market (EIM) and with expanded penetrations of intermittent renewable energy sources. P7 is also consistent with Idaho Power's goals related to responsibly transitioning away from coal-fired generating capacity.

Action Plan

Table 1.3 provides the schedule of action items Idaho Power anticipates over the next four years. Further discussion surrounding the action plan is provided in Chapter 10.

Table 1.3 Action plan[5]

Year	Resource	Action	Action Number
2017–2018	EIM	Continue planning for western EIM participation beginning in April 2018.	1
2017–2018	Loss-of-load and solar contribution to peak	Investigate solar PV contribution to peak and loss-of-load probability analysis.	2
2017–2019	North Valmy Unit 1	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.	3
2017–2021	Jim Bridger units 1 and 2	Plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.	4
2017–2020	B2H	Conduct ongoing permitting, planning studies, and regulatory filings.	5
2018–2026[6]	B2H	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	6
2017–2021	Boardman	Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.	7
2017–2021	Gateway West	Conduct ongoing permitting, planning studies, and regulatory filings.	8
2017–2021	Energy efficiency	Continue the pursuit of cost-effective energy efficiency.	9
2017–2021	Carbon emission regulations	Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.	10
2017–2021	North Valmy Unit 2	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.	11

[5] The B2H short-term action plan is 2017 to 2026. All other action plan items are for 2017 to 2021.

[6] B2H in-service date of 2024 or later, subject to coordination of activities with project co-participants.

2. Political, Regulatory, and Operational Issues

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor's Office of Energy and Mineral Resources (OEMR), the Idaho Strategic Energy Alliance allows various stakeholders to represent and participate in developing energy plans and strategies for Idaho's energy future. The Idaho Strategic Energy Alliance is Idaho's primary mechanism for advancing energy production, energy efficiency, and energy business in Idaho.

The purpose of the Idaho Strategic Energy Alliance is to develop a sound energy portfolio for Idaho that includes diverse energy resources and production methods; the highest value to the citizens of Idaho; quality stewardship of environmental resources; and an effective, secure, and stable energy system.

Idaho Power representatives serve on both the Idaho Strategic Energy Alliance Board of Directors and several volunteer task forces on the following topics:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach
- Energy storage

Idaho Energy Primer

In 2016, the Idaho Strategic Energy Alliance prepared the 2016 Idaho Energy Primer (Primer). The Primer is a resource to help citizens of Idaho better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.

The Primer provides information about energy resources, production, distribution, and use in the state. Having reliable, affordable, and sustainable energy for individuals, families, and businesses while protecting the environment is critical to achieving sustainable economic growth and maintaining our quality of life.

The 2016 Idaho Energy Primer finds that, despite Idaho's reliance on imported energy, Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy. In a year with average hydroelectric generation, about 65 percent of Idaho's electricity is generated in Idaho. The other 35 percent comes primarily from coal-fired power plants located in neighboring states. Idaho has the fifth lowest carbon dioxide output of any state because of its abundant hydropower, wind, biomass, and other renewable energy sources.

State of Oregon Biennial Energy Plan: 2015–2017

The Oregon Department of Energy (ODOE) completes a Biennial Energy Plan every two years. The ODOE's Biennial Energy Plan provides information on Oregon's energy supply and consumption, shows how long-term energy costs have been reduced, and highlights current energy issues and trends.

The ODOE 2015–2017 Biennial Energy Plan highlights some of the current challenges and opportunities for Oregon, including the following:

- Accelerated demand for energy efficiency due to a growing population in Oregon that drives increases in demand and energy use
- Continued development of clean energy that can help reduce the environmental impact of energy use
- Reduction of carbon emissions
- Energy supply due to numerous market forces that affect the type, number, and geographic diversity of energy siting projects

The 2015–2017 Biennial Energy Plan showed Oregon's energy supply consisting of primarily hydroelectric power, followed by coal and natural gas. The most significant change in electricity consumption from 2005 to 2010 is the growth of natural gas, from 3.3 percent to 16.24 percent. Wind has also grown consistently, increasing from 0.25 percent to 4.31 percent. Oregon's generation mix includes power generated outside of the state and delivered to Oregon consumers.

FERC Relicensing

Bayha Island

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

Idaho Power's remaining and most significant ongoing relicensing effort is for the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 34 percent of the company's total generating capacity. The current license for the HCC expired in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under annual licenses issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC has been processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1973* (ESA); the *Clean Water Act of 1972* (CWA); and other applicable federal laws. FERC is currently waiting for Oregon and Idaho to issue Section 401 certifications under the CWA. The certifications are expected on or before April 13, 2018.

Efforts to obtain a new multi-year license for the HCC are expected to continue until a new license is issued, which Idaho Power estimates will occur no earlier than 2021. Considering the costs incurred and the considerable passage of time, in December 2016 Idaho Power filed an application with the IPUC requesting a determination that Idaho Power relicensing expenditures of $220.8 million through year-end 2015 were prudently incurred and therefore eligible for inclusion in retail rates. 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 the protection, mitigation, and enhancement (PM&E) packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include the following:

1. Coordinating the relicensing process

2. Consulting with regulatory agencies, tribes, and interested parties on resource and legal matters

3. Preparing and conducting studies on fish, wildlife, recreation, archaeological resources, historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes

4. Analyzing data and reporting study results

5. Preparing all necessary reports, exhibits, and filings to support ongoing regulatory processes related to the relicensing effort.

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

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2017 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

Idaho Water Issues

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

Idaho Power, along with other Snake River Basin water-right holders, was engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of the State of Idaho in October 1984. Idaho Power filed claims for all its hydroelectric water rights in the SRBA. As a result of the SRBA, the company's water rights were adjudicated, resulting in the issuance of partial water-right decrees. The Final Unified Decree for the SRBA was signed on August 25, 2014.

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power over the company's water rights at the Swan Falls Project. The agreement stated

Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The Swan Falls Agreement placed the portion of the company's water rights beyond the minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the State of Idaho. 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 as a result 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 the company's hydroelectric water rights to aquifer recharge.

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

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

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

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

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

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

Renewable Integration Costs

Idaho Power has completed two wind integration studies and two solar integration studies since the mid-2000s. These studies increased the company's understanding of the impacts and costs associated with integrating variable and intermittent resources without compromising reliability. The variable and uncertain production from wind and solar resources requires Idaho Power to provide additional balancing reserves from existing dispatchable generating resources, which results in opportunity costs and corresponding increases in power-supply expenses. Idaho Power completed the most recent wind integration study in 2013 and the most recent solar integration study in 2016. The costs found by these studies are the basis for renewable integration costs as provided in Idaho Schedule 87 and Oregon Schedule 85.

The results of the integration studies show periods of low customer demand to be the most difficult to cost-effectively integrate intermittent resources. During low demand periods, other existing resources are often already running at minimum levels or may already be shut off. Under these conditions, curtailment of the variable resources may be necessary to keep generation balanced with customer load. The integration studies also demonstrate the frequency of curtailment events is expected to increase as additional variable resources are added to the system.

For the IRP, integration costs for existing wind and solar resources are common to all portfolios analyzed and are not included in the portfolio cost accounting. However, portfolios with new solar resources include costs consistent with schedules 87 (Idaho) and 85 (Oregon) for the new resources. The schedule of integration costs is provided in *Appendix C—Technical Appendix.*

Community Solar Pilot Program

In the 2009 IRP, Idaho Power proposed a solar PV pilot project. Due to a few extenuating circumstances, as detailed in the 2015 IRP, the pilot project was not pursued. However, customer interest in distributed solar generation continued to grow and was the subject of many 2015 IRP discussions. Late in the 2015 IRP public process, Idaho Power was approached by several interested parties and asked to consider sponsoring a community solar project.

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

For the pilot program, the company proposed to build and own a 500-kilowatt (kW) single-axis tracking community solar array in southeast Boise that would allow a limited number of Idaho Power's Idaho customers to voluntarily subscribe to the generation output on a first-come basis. Participating customers would be required to pay a one-time, upfront subscription fee, and in return would receive a monthly bill credit for their designated share of the energy produced from the array. Because the company's 2015 IRP did not reflect a load-serving need for the proposed solar resource, the overall program design was intended to result in program participants covering the full cost of the project with nominal impact to non-participating customers.

The IPUC approved the pilot program on October 31, 2016, and marketing efforts for customer subscription began immediately. At the time of publishing, the Community Solar Pilot Program was not fully subscribed, with only 15.5 percent of the allotted subscriptions purchased. The company is currently evaluating the future of the Community Solar Pilot Program.

Energy Imbalance Market

In November 2014, the California Independent System Operator (CAISO) and PacifiCorp created the western EIM to enhance real-time coordination of market trading activity. The western EIM is a five-minute market administered by a single market operator, CAISO, which uses an automatic economic dispatch model to find and determine the least-cost energy resources to serve real-time customer demand across a wide geographic area. The western EIM focuses solely on real-time imbalances and allows EIM participants to retain all balancing responsibilities and transmission provider duties. In addition, the western EIM uses generating resources from market participants to meet real-time load efficiently and cost-effectively across the entire western EIM footprint.

Idaho Power is scheduled to begin participating in the western EIM in April 2018, at which time the western EIM participants will include PacifiCorp, CAISO, NV Energy, Puget Sound Energy, Arizona Public Service Company, and PGE. Market participants voluntarily bid resources into the western EIM, and the market operator provides least-cost dispatch instructions and generates a locational marginal price to be used for energy imbalances, factoring in load, available generation, and existing transmission constraints. Benefits to joining the western EIM include the following:

- The economic efficiency of an automated dispatch model for both generation and transmission line congestion
- Savings due to diversity of loads and variability of resources within the expanded footprint
- Reduced operational risk due to enhanced system reliability
- The ability to better support the integration of renewable resources

Since its inception, the western EIM has resulted in significant cost savings for its participants. Idaho Power expects its participation in the western EIM will similarly result in net power-supply expense savings for customers.

Renewable Energy Certificates

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

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1 MWh of electricity produced. RECs and the electricity produced by a certified renewable resource can either be sold together (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level renewable portfolio standard (RPS). A RPS is a policy requiring a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy. Retired RECs also enable the retiring entity to claim the renewable energy attributes of the corresponding amount of energy delivered to customers.

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

REC prices depend on many factors, including the following:

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

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

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, each dollar of green power purchased represents 100 kilowatt-hours (kWh) of renewable energy delivered to the regional power grid, providing the Green Power Program participant associated claims for the renewable energy. Most the participant funds are used to purchase green power from renewable projects in the Northwest and to support Solar 4R Schools, a program designed to educate students about renewable energy by placing solar installations on school property. A portion of the funds are used to market the program, with the prospect of increasing participation in the program. On behalf of program participants, Idaho Power obtains and retires RECs. In 2016, Idaho Power purchased and subsequently retired 15,360 RECs on behalf of Green Power participants. Green Power is sourced from renewable energy projects in Idaho, Oregon, and Washington.

Renewable Portfolio Standard

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established an RPS for electric utilities and retail electricity suppliers. Under the Oregon RPS, Idaho Power is classified as a smaller utility because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. In 2015, per Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.3 percent of Oregon's total electric sales. As a smaller utility, Idaho Power will have to meet a 5- or 10-percent RPS requirement beginning in 2025. In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25 percent by 2025 to 50 percent renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change.

The State of Idaho does not currently have an RPS.

Clean Power Plan

Rule History

On June 2, 2014, the Environmental Protection Agency (EPA), under President Obama's Climate Action Plan, released a proposal to regulate CO_2 emissions from existing power plants under the CAA Section 111(d) (Clean Power Plan). EPA's proposed Clean Power Plan included ambitious, mandatory CO_2 reduction targets for each state designed to achieve nationwide 30-percent CO_2 emission reductions over 2005 levels by 2030. On October 23, 2015, the final Clean Power Plan was published in the Federal Register, and the EPA proposed a Federal Implementation Plan.

Due to ongoing litigation about the legality of the rule, on February 9, 2016, the U.S. Supreme Court issued orders staying the Clean Power Plan pending resolution of challenges to the rule. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) heard oral arguments en banc before a panel of 10 judges on September 27, 2016.

On March 28, 2017, President Donald Trump issued an Executive Order on Energy Independence that, among other things, directs the EPA to review and, if appropriate, suspend, revise, or rescind the Clean Power Plan. On March 31, 2017, Scott Pruitt, the Director of the EPA, notified each state's governor that if any deadlines under the Clean Power Plan become relevant in the future, the EPA will toll its requirement for states to comply with the regulation.

On April 28, 2017, the D.C. Circuit Court approved an EPA motion to hold the Clean Power Plan case in abeyance for 60 days, or until June 27, 2017. According to the EPA's motion, "EPA should be afforded the opportunity to fully review the Clean Power Plan and respond to the President's direction in a manner that is consistent with the terms of the Executive Order, the Clean Air Act, and the agency's inherent authority to reconsider past decisions."[7] In the order granting the abeyance, the EPA was directed to file status reports every 30 days. The court also ordered the parties to file supplemental briefs on or before May 15, 2017, addressing whether the challenge should be remanded to the EPA rather than held in abeyance.

Clean Power Plan Final Rule

The final Clean Power Plan establishes interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired electric generating units (EGU):

- Fossil fuel-fired EGUs (coal- and oil-fired power plants)
- Natural gas-fired combined cycle generating units

[7] *West Virginia v. EPA*, No. 15-1363 (D.C. Cir. March 28, 2017).

To maximize the range of choices available to states in implementing the standards and to utilities meeting them, the EPA has established interim and final statewide goals in three forms:

1. A rate-based state goal measured in pounds per MWh
2. A mass-based state goal measured in total short tons of CO_2
3. A mass-based state goal with a new source complement measured in short tons of CO_2

States must develop and implement plans that ensure the power plants in their state—individually, collectively, or in combination with other measures—achieve the interim CO_2 emission performance rates from 2022 to 2029 and the final CO_2 emission performance rates for their state by 2030.

In the final Clean Power Plan, the EPA determined the best system of emissions reduction (BSER) to reduce CO_2 from fossil fuel-fired power plants consisted of three building blocks:

1. Building Block 1—Improve efficiency in existing coal-fired power plants.
2. Building Block 2—Re-dispatch generation from existing coal-fired power plants to natural gas combined-cycle plants.
3. Building Block 3—Increase generation from non-CO_2-emitting resources.

The EPA applied the building blocks to all coal and natural gas power plants in each region to produce a regional emission performance rate for each category. From the resulting regional coal and natural gas power plant rates, the EPA chose the most readily achievable rate for each category to arrive at equitable CO_2 emission performance rates that represent the BSER. The same CO_2 emission performance rates were then applied to all affected sources in each state to arrive at individual statewide rate- and mass-based goals. Each state has a different goal based on its own mix of affected sources.

The final rule also gives states the option to work with other states on multi-state approaches, including emissions trading.

While specific actions based on the EPA's review of the Clean Power Plan are forthcoming, each resource portfolio in the 2017 IRP is compliant with the final Clean Power Plan mass-based emission limits. Due to the executive order and the Pruitt letter, Idaho Power anticipates more stringent compliance measures will not be required under the Clean Power Plan.

Further discussion of these CO_2 emission constraints is provided in Chapter 9. Projected CO_2 emissions for each analyzed resource portfolio are provided in *Appendix C—Technical Appendix*.

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3. Idaho Power Today

Customer Load and Growth

In 1992, Idaho Power served approximately 306,000 general business customers. Today, Idaho Power serves nearly 534,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,164 MW in 1992 to over 3,400 MW. On July 2, 2013, the peak-hour load reached 3,407 MW—the system peak-hour record, nearly matched in 2015 (3,402 MW).

Construction in downtown Boise.

Average firm load increased from 1,280 average MW (aMW) in 1992 to 1,750 aMW in 2016 (load calculations exclude the load from the former special-contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1. The data in Table 3.1 suggests each new customer adds over 5.5 kW to the peak-hour load and over 2 average kW (akW) to the average load.

Since 1992, Idaho Power's total nameplate generation has increased from 2,694 MW to 3,594 MW. The 900-MW increase in capacity represents enough generation to serve nearly 161,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1992.

Idaho Power has added about 228,000 new customers since 1992. The peak-hour and average-energy calculations mentioned earlier suggest the additional 228,000 customers require about 1,250 to 1,300 MW of additional peak-hour capacity and about 450 to 500 aMW of energy.

Idaho Power anticipates adding approximately 11,100 customers each year throughout the 20-year planning period. The expected-case load forecast for the entire system predicts summer peak-hour load requirements will grow over 50 MW per year, and the average-energy requirement is forecast to grow over 15 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

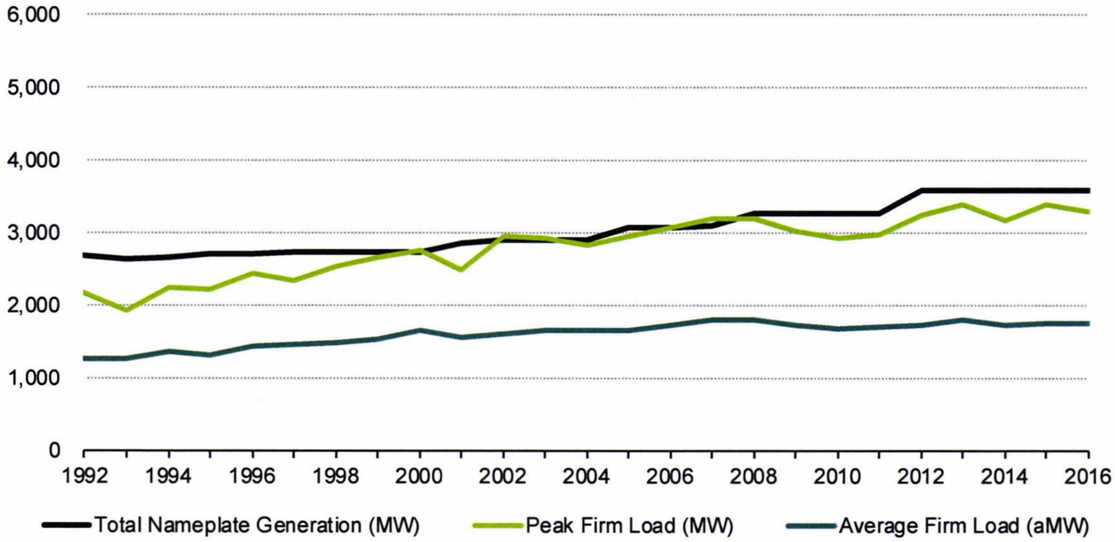


Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1992	2,694	2,164	1,281	306,292
1993	2,644	1,935	1,274	316,564
1994	2,661	2,245	1,375	329,094
1995	2,703	2,224	1,324	339,450
1996	2,703	2,437	1,438	351,261
1997	2,728	2,352	1,457	361,838
1998	2,738	2,535	1,491	372,464
1999	2,738	2,675	1,552	383,354
2000	2,738	2,765	1,654	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,623	414,062
2003	2,912	2,944	1,658	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,661	456,104
2006	3,085	3,084	1,747	470,950
2007	3,093	3,193	1,810	480,523
2008	3,276	3,214	1,816	486,048
2009	3,276	3,031	1,744	488,813
2010	3,276	2,930	1,680	491,368
2011	3,276	2,973	1,712	495,122
2012	3,594	3,245	1,746	500,731
2013	3,594	3,407	1,801	508,051
2014	3,594	3,184	1,739	515,262
2015	3,594	3,402	1,748	524,325
2016	3,594	3,299	1,750	534,528

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

2016 Energy Sources

Idaho Power's energy sources for 2016 are shown in Figure 3.2. Idaho Power-owned generating capacity was the source for 73 percent of the energy delivered to customers. Hydroelectric production from company-owned projects was the largest single source of energy at 39 percent of the total. Coal contributed 24 percent, and natural gas- and diesel-fired generation contributed 10 percent. Purchased power comprised 27 percent of the total energy delivered to customers. Of the purchased power, about a third, or 9 percent of the total delivered energy, was from the wholesale electric market. The remaining purchased power was from long-term energy contracts (*Public Utility Regulatory Policies Act of 1978* [PURPA] and power purchase agreements [PPA]) primarily from wind, hydro, geothermal, biomass, and solar projects (in order of decreasing percentage). While Idaho Power enables production from PURPA and PPA projects, the company sells RECs associated with the production and does not represent the energy from these projects as energy delivered to customers.

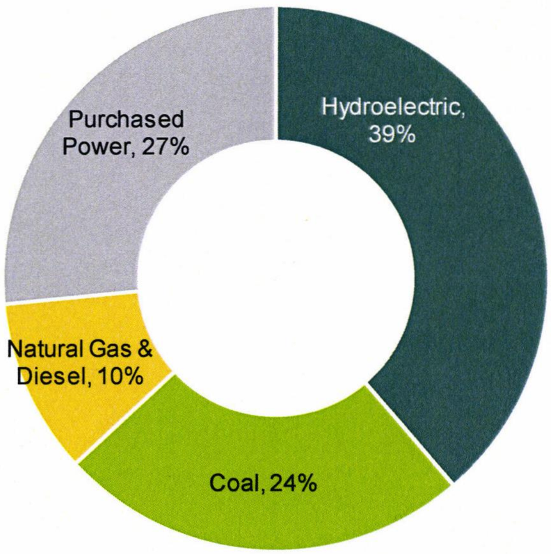


Figure 3.2 2016 energy sources

Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are presented in *Appendix C—Technical Appendix*. Table 3.2 shows all of Idaho Power's existing company-owned resources, nameplate capacities, and general locations.

Table 3.2 Existing resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	585.4	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	12.5	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	8.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
North Valmy	Coal	283.5	North Central Nevada
Langley Gulch	Natural Gas—CCCT*	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT**	172.8	Southwest Idaho
Danskin	Natural Gas—SCCT**	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,594.4**	

*Combined-cycle combustion turbine
**Simple-cycle combustion turbine

The following sections describe Idaho Power's existing supply-side generation 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 1,709 MW and an annual generation equal to approximately 960 aMW, or 8.4 million MWh under median water conditions.

Hells Canyon Complex

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

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

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

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

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood-control directions received from the US Army Corps of Engineers (COE) as outlined in Article 42 of the existing FERC license.

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

The US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River Basin above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle

Snake River (mid-Snake) projects, with all the flow augmentation eventually passing through the HCC before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the Fall Chinook Program adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During fall Chinook operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C. J. Strike, Bliss, Lower Salmon, Upper Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, and C. J. Strike projects. These three projects are operated within the FERC license requirements to coincide with daily system peak demand when load-following capacity is available.

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

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

Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the hydroelectric production is needed are especially beneficial.

Acquiring water through the water bank also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC. The company does not currently have any water lease agreements but plans to continue to evaluate potential water-lease opportunities in the future.

Cloud Seeding

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

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

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

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

AgI is a very efficient ice nuclei, allowing it to be used in minute quantities. It has been used as a seeding agent in numerous western states for decades without any known harmful effects.[8] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 28 percent annually, with an annual average of 14 percent. Idaho Power estimates cloud seeding provides an additional 346,000 acre-feet from the upper Snake River and 272,000 acre-feet from the Payette River. At program build-out, Idaho Power estimates additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,000,000 acre-feet. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

[8] weathermodification.org/images/AGI_toxicity.pdf

For the 2016 to 2017 winter season, Idaho Power continued to collaborate with the State of Idaho and water users to augment water supplies with cloud seeding. The program included 30 remote-controlled, ground-based generators and two aircraft for Idaho Power-operated cloud seeding in the west-central mountains of Idaho (Payette, Boise, and Wood River basins). The Upper Snake River Basin program included 25 remote-controlled, ground-based generators and one aircraft operated by Idaho Power targeting the Upper Snake, as well as 25 manual, ground-based generators operated by a coalition of stakeholders in the Upper Snake. The 2016 to 2017 season provided abundant storms and seeding opportunities. Suspension criteria were met in some areas in early February, and operations were suspended for the season for all target areas by early March.

Coal Facilities

Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

The 2017 IRP considers a range of scenarios for Jim Bridger units 1 and 2. The scenarios relate to varying options for capital investments into environmental retrofits. The scenarios are described in Chapter 7.

North Valmy

Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

A baseline assumption of the 2017 IRP has Idaho Power retiring its share of North Valmy Unit 1 at year-end 2019 and its share of North Valmy Unit 2 at year-end 2025. Further discussion surrounding this assumption is provided in Chapter 7.

Boardman

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

The 2017 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the EPA related to compliance with

Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NOx) emissions.

Natural Gas Facilities

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens STG-5000F4 combustion turbine and one 131.5-MW Siemens SST-700/SST-900 reheat steam turbine. The Langley Gulch plant, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012.

Langley Gulch Power Plant

Danskin

Idaho Power owns and operates the 271-MW Danskin natural gas-fired SCCT facility. The facility consists of one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse W251B12A combustion turbines. The Danskin facility is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

Bennett Mountain

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

Salmon Diesel

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

Solar Facilities

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

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

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

Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid.
The majority of net metering customers use solar PV systems. As of March 1, 2017, there were 1,045 solar PV systems were interconnected through the company's net metering service with a total capacity of 8.079 MW. At that time, the company had received completed applications for an additional 110 net metered solar PV systems, representing an incremental capacity of 1.376 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.3 and Table 3.4.

Table 3.3 Net metering service customer count as of March 1, 2017

Resource Type	Active	Pending	Total
Solar PV	1,045	110	1,155
Wind	62	2	64
Other/hydroelectric	10	1	11
Total	**1,117**	**113**	**1,230**

Table 3.4 Net metering service generation capacity (MW) as of March 1, 2017

Resource Type	Active	Pending	Total
Solar PV	8.079	1.3760	9.455
Wind	0.378	0.0016	0.380
Other/hydroelectric	0.147	0.0120	0.159
Total	**8.604**	**1.3900**	**9.994**

Oregon Solar PV Pilot Program and Oregon Solar PV Capacity Standard

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

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

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

Under the previously required Oregon Solar PV Capacity Standard, Idaho Power was required to either own or purchase the generation from a 500-kW utility-scale solar PV facility by 2020. This requirement was repealed, effective March 8, 2016, pursuant to Oregon Senate Bill 1547.

PURPA

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

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

As of April 1, 2017, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,135 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, 128 were on-line as of April 1, 2017, with a cumulative nameplate rating of approximately 1,115 MW. Figure 3.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

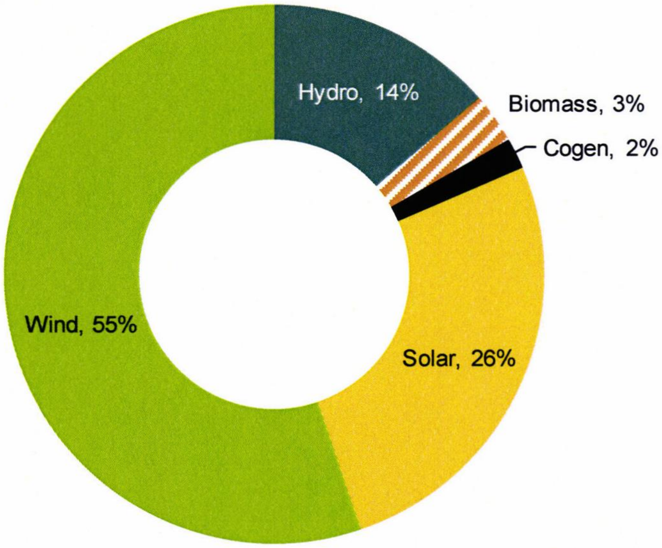


Figure 3.3 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. Generation from PURPA contracts is forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2017 IRP was completed in December 2016.

Power Purchase Agreements

Elkhorn Valley Wind Project

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

Elkhorn Valley Wind Project, Union County, Oregon

Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 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. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. The Raft River geothermal project has rarely exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is currently receiving negligible RECs from the project. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of all RECs generated by the project.

Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project.

Clatskanie Energy Exchange

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

Wholesale Contracts

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

Power Market Purchases and Sales

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

Transmission MW Import Rights

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

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

However, Idaho Power does not own exclusive rights to all the transmission capacity available on each path. Idaho Power is either a partial owner of a path shared with other partners, or other entities have acquired long-term purchased capacity for a portion of a path. Idaho Power is allowed to set aside portions of its transmission capacity to import energy for load service. Beyond the existing set-aside capacity and contractual obligations, Idaho Power's import capacity on these paths is fully allocated, except for 86 MW of available capacity on Path 19.

4. Future Supply-Side Generation and Storage Resources

Generation Resources

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. As discussed in Chapter 5, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources and storage technologies considered when Idaho Power developed the resource portfolios for the 2017 IRP. While a variety of resource options was analyzed, the portfolio design for the IRP allowed the selection of a subset for inclusion in resource portfolios.

The primary source of cost information for the 2017 IRP is *Lazard's Levelized Cost of Energy Analysis*.[9] Lazard, a leading independent financial advisory and asset management firm, issued the levelized cost report in December 2016. Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the age of the information. Refer to Chapter 7 for a full list of all the resources considered and cost information. All cost information presented is in 2017 dollars.

Renewable Resources

Renewable energy resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. Renewable resources are discussed in general terms in the following sections.

Solar

The primary types of solar technology are utility-scale PV and distributed PV. In general, PV technology converts solar energy collected from sunlight shining on panels of solar cells into electricity. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy passes through an inverter, converting it to alternating current (AC) that can be used on-site or sent to the grid. Even on cloudy days, a solar PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter (m^2)

[9] Lazard. 2016. Lazard's levelized cost of energy analysis 10.0 (LCOE 10.0). https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the southwest desert has the highest solar potential in the US.

In designing resource portfolios that included solar resources, Idaho Power chose the utility-scale PV technology because of its compliance to EPA's proposed CAA Section 111(d) regulation, its flexibility, and its lower overall cost. Modern solar PV technology has existed for several years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPSs, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2017 IRP for utility-scale PV resources is based on the Lazard report, which estimates a cost of $1,375 per kW for PV with a single-axis tracking system. The 25-year levelized cost of energy for PV with single-axis tracking is $74 per MWh with a 27-percent annual capacity factor.

Rooftop solar was considered in two forms as part of the 2017 IRP. The capital-cost estimate used in the 2017 IRP for residential rooftop solar PV resources is based on the Lazard report, which estimates a cost of $2,400 per kW for PV on residential rooftops. The 25-year levelized cost of energy for residential rooftop solar PV resources is $153 per MWh with a 21-percent annual capacity factor. The capital-cost estimate used for commercial and industrial rooftop solar PV resources is based on the Lazard report, which estimates a cost of $2,925 per kW for PV on commercial and industrial rooftops. The 25-year levelized cost of energy for commercial and industrial rooftop solar PV resources is $179 per MWh with a 21-percent annual capacity factor. The cost of rooftop solar PV resources is recognized to vary by region, and the Lazard-reported costs are not indicative of solar PV costs in Idaho Power's service area.[10] Rooftop solar PV cost estimates vary by source, and based on Idaho Power's review of sources, the Lazard-reported costs are toward the lower end of the cost range. For example, the Department of Energy (DOE) Tracking the Sun study indicates rooftop solar pricing of approximately $4,000 per kW for residential installations and $3,000 per kW for non-residential installations.[11]

Energy production from solar PV arrays declines over time. This is known as PV degradation. For the 2017 IRP, Idaho Power assumes a 0.5 percent annual degradation rate of energy production from solar PV arrays.

[10] The Open PV Project, NREL, https://openpv.nrel.gov/.

[11] DOE. August 2016. Tracking the sun IX, the installed price of residential and non-residential photovoltaic systems in the United States. https://emp.lbl.gov/sites/default/files/tracking_the_sun_ix_report.pdf.

Solar Capacity Credit

Idaho Power applied the solar capacity credit calculations derived from the 2015 IRP. As part of the 2015 IRP process, Idaho Power, interested members of the IRPAC, and interested members of the public formed a study group separate from the IRPAC to evaluate solar peak-hour capacity factors. The group formally met and conducted meetings and conversations with members of the study group. Idaho Power updated the solar PV peak-hour capacity factors based on guidance from members of the solar work group.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to the Idaho Power system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2017 IRP are reported in Table 4.1.

Table 4.1 Solar capacity credit values

PV System Description	Peak-Hour Capacity Credit
South orientation	28.4%
Southwest orientation	45.5%
Tracking	51.3%

Geothermal

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

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

Cost estimates and operating parameters used for binary-cycle geothermal generation in the 2017 IRP are based on data from the Northwest Power and Conservation Council (NWPCC) Seventh Power Plan. The capital-cost estimate used in the 2017 IRP for geothermal resources is $4,675 per kW, and the 25-year levelized cost of energy is $111 per MWh based on an 88-percent annual capacity factor.

Hydroelectric

Hydroelectric power is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. Idaho Power believes the development of new, large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydroelectric sites have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PURPA contracts with Idaho Power.

Small Hydroelectric

Small hydroelectric projects, such as ROR and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital-cost estimate used in the 2017 IRP for small hydroelectric resources is $3,753 per kW, and the 75-year levelized cost of energy is $165 per MWh.

Wind

A typical wind project consists of an array of wind turbines ranging in size from 1 to 3 MW each. The majority of potential wind sites in southern Idaho lie between the south-central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles per hour are prime locations for wind development.

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain regions, as evidenced by the number of existing projects. Wind resources present operational challenges for utilities due to the variable and intermittent nature of wind generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2017 IRP, Idaho Power used an annual average capacity factor of 28 percent and an on-peak capacity factor of 5 percent for peak-hour planning. The capital-cost estimate used in the IRP for wind resources is $1,475 per kW, and the 25-year levelized cost of energy is $111 per MWh, which includes a wind integration cost of $16.33 per MWh.

Biomass

Biomass resource types considered in the 2017 IRP include wood-burning resources and anaerobic digesters. Wood-burning resources typically rely on a steady supply of woody residue collected from forested areas. Fuel supply can be an issue for these types of plants as the radius of the area used to collect fuel is expanded. Several anaerobic digesters have been built in southern Idaho due to the size of the dairy industry and the quantity of fuel available. The 2017 IRP considered anaerobic digesters as a best fit for the service area.

The capital-cost estimate used in the 2017 IRP for an anaerobic digester project is $6,522 per kW for a 35-MW facility. The anaerobic digester is expected to have an annual capacity factor of 85 percent. Based on the annual capacity factors, the 30-year levelized cost of energy is $133 per MWh for the anaerobic digester.

Conventional Resources

While much attention has been paid to renewable resources over the past few years, conventional generation resources are essential to provide dispatchable capacity, which is critical in maintaining the reliability of an electrical power system. These conventional generation technologies include natural gas-fired resources, nuclear, and coal.

Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine to generate electricity. CCCTs are typically used for baseload energy, while less-efficient SCCTs are used to generate electricity during peak-load periods. Additional details on the characteristics of both types of natural gas resources are presented in the following sections.

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. The additional cost as necessary for expanded gas pipeline allocation is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial, dispatchable power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits fewer emissions when compared to coal, therefore requiring fewer pollution controls. Modern CCCT facilities are highly efficient and can achieve efficiencies of approximately 60 percent (lower heating value).

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

Several CCCT plants, similar to Idaho Power's Langley Gulch project, are planned in the region due to a sustained depression in natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate intermittent resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the IRP for a CCCT (1 x 1) resource is $1,246 per kW, and the 30-year levelized cost of energy at a 70-percent annual capacity factor is $64 per MWh.

Simple-Cycle Combustion Turbines

Simple cycle, natural gas-turbine 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 not typically economical to operate other than to meet peak-hour load requirements.

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

Idaho Power has approximately 430 MW of SCCT capacity. As peak summertime electricity demand continues to grow within Idaho Power's service area, SCCT generating resources remain a viable option to meet peak load during critical high-demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest.

The 2017 IRP evaluated a 170-MW industrial-frame (F class) SCCT unit. The capital-cost estimate used in the 2017 IRP is $878 per kW. The industrial-frame unit is expected to have an annual capacity factor of 10 percent.

Based on an annual capacity factor of 10 percent, the 35-year levelized cost of energy is $197 per MWh for the industrial-frame SCCT unit. If Idaho Power were to identify the need for a SCCT, it would evaluate SCCT technologies in greater detail prior to issuing a request for proposal (RFP) to determine which technology would provide the greatest benefit.

Reciprocating Engines

Reciprocating 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. Because they are mounted on a common baseframe, the entire unit can be assembled, tuned, and tested in the factory before being delivered to the power plant location, which minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple, identical units, which allows each unit to run at its best efficiency point once started. As more generation is needed, additional units are started. This configuration also allows for relatively inexpensive future expansion of the plant capacity. Reciprocating engines provide unique benefits to the electrical grid. They are extremely flexible in the sense that they can provide ancillary services to the grid in a few minutes. Engines can go from a cold start to full-load in 10 minutes.

For the IRP, Idaho Power modeled a reciprocating engine similar to the 34SG model manufactured by Wärtsilä with a nameplate rating of approximately 18 MW. The capital-cost estimate used for a reciprocating engine resource is $775 per kW, and the 40-year levelized cost of energy at a 25-percent annual capacity factor is $94 per MWh.

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 a steam host. Generation technologies frequently used in CHP projects are gas turbines or engines with a heat-recovery unit.

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

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different.

Recognizing the actual cost of a CHP resource varies depending on the specific facility being considered, the capital-cost estimate used in the 2017 IRP for CHP is $2,213 per kW, and the 40-year levelized cost of energy evaluated at an annual capacity factor of 80 percent is $71 per MWh.

Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for some time, and Idaho Power has continued to evaluate various technologies in the IRP. Due to the Idaho National Laboratory (INL) site in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor (SMR) could be built on the site. For the 2017 IRP, high capital costs coupled with a great amount of uncertainty in waste-disposal issues prevented a nuclear resource from being included in the portfolio analysis. Recent large-scale nuclear development in the US has proven to be fraught with project delays and projected construction cost overruns exceeding $1 billion. In addition, the 2011 earthquake and tsunami in Japan, and the impact on the Fukushima nuclear plant, created a global concern over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to know the full impact this disaster will have on the future of nuclear power generation. While Idaho Power does not currently view traditional nuclear resources as a viable supply-side resource option for the company, it continues to monitor the advancement of SMR technology and will evaluate it in the future as the Nuclear Regulatory Commission reviews proposed SMR designs in the coming years.

For the 2017 IRP, a 50-MW small modular plant was analyzed. The capital-cost estimate used in the IRP for an advanced SMR nuclear resource is $6,126 per kW, and the 40-year levelized cost of energy, evaluated at an annual capacity factor of 90 percent, is $163 per MWh.

Coal Resources

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

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

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

The addition of CO_2-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. CO_2 has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of CO_2 produced would require the development of underground sequestration methods.

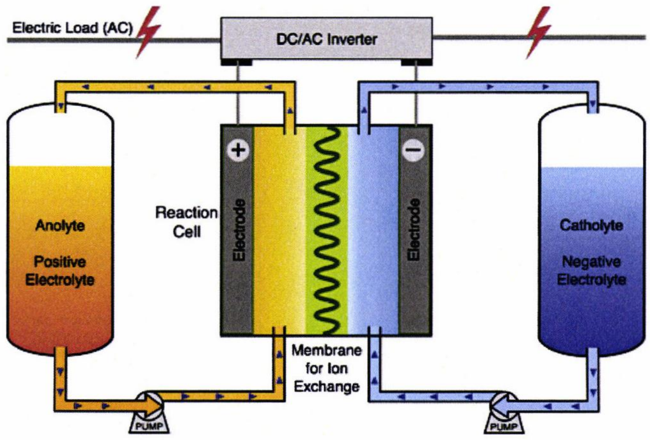
Carbon sequestration involves taking captured CO_2 and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. No new coal-based energy resources were modeled as part of the 2017 IRP.

Storage Resources

RPSs and PURPA have spurred the development of renewable resources in the Pacific Northwest, leading to periodic oversupply of energy in the region. Mid-Columbia wholesale market prices for electricity continue to remain relatively low. At the same time, retail rates for electricity continue to grow, as utilities must pass the cost of building these resources on to customers. The oversupply issue has grown to the point where at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to decrease into negative values.

As more intermittent renewable resources like wind and solar continue to be built within the region, the need for energy storage is amplified. Many storage technologies are at various stages of development, such as hydrogen storage, compressed air, and flywheels. The 2017 IRP considered and evaluated multiple energy storage technologies, including battery storage, ice-based thermal energy storage (TES), and pumped hydro storage.

Battery Storage



Basic illustration of a flow battery.[12]

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery storage technologies at various stages of development. The 2017 IRP analyzed the vanadium redox-flow battery (VRB), lithium-ion battery systems and zinc battery systems.

Advantages of the VRB technology include its low cost, long life, and scalability to utility/grid applications. Most battery technologies are not a good fit for utility-scale applications because they cannot be easily or economically scaled to much larger sizes. The VRB overcomes much of this issue because the capacity of the battery can be increased by increasing the size of the tanks that contain the electrolytes, which also helps keep the cost relatively low.

VRB technology also has an advantage in maintenance and replacement costs, as only certain components need to be replaced about every 10 years, whereas other battery technologies require a complete and often more frequent replacement of the battery depending on the duty cycle. For the IRP, the capital-cost estimate for the VRB is $3,736 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 4 percent, is $2,010 per MWh. Idaho Power recognizes the continued technological development of VRB batteries used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and the scalability of this technology in the coming years.

In recent months, lithium-ion battery systems have gone on-line commercially in the US on the west coast. Lithium-ion battery storage systems realize high charging and discharging efficiencies. Lithium-based energy storage devices present possible safety concerns due to overheating.

For the IRP, the capital-cost estimate for lithium-ion battery storage is $3,114 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 14 percent, is $476 per MWh. Idaho Power recognizes the continued technological development of lithium-ion batteries

[12] Source: http://wernerantweiler.ca/blog.php?item=2014-09-28

used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and the scalability of this technology in the coming years.

A third type of battery storage system analyzed in the 2017 IRP was zinc battery storage. Zinc battery storage systems are capable of deep discharge cycles and are relatively low cost due to the abundance of the primary metals in a zinc battery. Zinc-based energy storage devices do present concerns due to their lack of proven utility-scale application. Zinc battery systems are typically less efficient than other types of battery storage technologies.

For the IRP, the capital-cost estimate for zinc battery storage is $2,010 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 7 percent, is $621 per MWh. Idaho Power recognizes the continued technological development of Zinc batteries and will continue to monitor price trends and the technical viability of this technology in the coming years.

Ice-Based TES

Ice-based TES is a concept developed to take advantage of the air conditioning (A/C) needs of mid-sized to large commercial buildings. The general concept is to create ice during low-load/low-price times (light load hours), then to use the ice for A/C needs during the high-load/higher-price times (heavy-load hours). While this concept does not specifically store electricity, it does shift the time the energy is consumed, with the overall goal of reducing peak daytime demand.

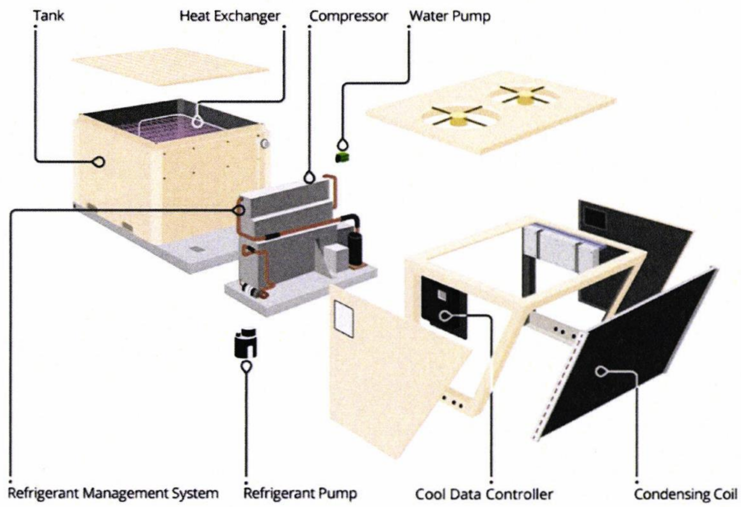


Illustration of an ice-based TES system.[13]

One company currently commercializing the ice-based TES technology is Ice Energy with their Ice Bear Energy Storage System. Requirements in California to develop energy storage have allowed several utilities to begin installing and testing this technology, with several installations of 5 MW to 15 MW in size. For the IRP, the capital-cost estimate used for this technology is

[13] Source: http://www.ice-energy.com/technology/ice-bear-energy-storage-system

$2,000 per kW, and the 20-year levelized cost of energy, evaluated at an annual capacity factor of 6 percent, is $508 per MWh.

Pumped Hydro Storage

Pumped storage is a type of hydroelectric power generation used to change the "shape" or timing of when electricity is produced. The technology stores energy in the form of water, pumped from a lower-elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

For pumped storage to be economical, there must be a significant differential (arbitrage) in the price of electricity between peak and off-peak times to overcome the costs incurred due to efficiency. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, Idaho Power continues to monitor the viability of pumped storage projects in the region. The capital-cost estimate used in the IRP for pumped storage is $2,352 per kW, and the 50-year levelized cost of energy, evaluated at an annual capacity factor of 20 percent, is $229 per MWh.

5. Demand-Side Resources

DSM Program Overview

Demand-side resources are the first selected resources in each IRP. No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective, achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. In the 2017 IRP, demand response provides 390 MW of committed peak summer capacity, while energy efficiency will reduce average annual loads by 273 aMW and 483 MW of peak reduction by the year 2036.

The Shade Tree Project provides free trees for residential customers in select counties to shade their homes. Shade trees, properly grown on the west side of a home, can help reduce energy needed for summer cooling by 15 percent or more. In 2016, Idaho Power distributed 2,070 trees.

Changes from the 2015 IRP

Methods for incorporating and accounting for energy efficiency and demand response resources in the 2017 IRP were similar to methods used in the 2015 IRP. As in the 2013 and 2015 IRPs, the planning case for energy efficiency as a resource potential was determined by a third-party consultant. Notably, the company's 20-year load forecast for the 2017 IRP accounted for all accumulated potential energy efficiency savings. As a result, over the last seven years of the IRP planning period (2030–2036), no adjustments to forecast loads were required to reflect incremental energy efficiency savings potential determined by the third party but not included in the load forecast. The alignment of the energy efficiency savings potential forecasts is a result of sharing data and assumptions from the 2015 potential study and the early results of the 2017 potential study. Another highlight for the 2017 IRP is the continued improvement in estimating peak contribution from energy efficiency that was first estimated using hourly load shapes in the 2015 IRP. Prior to the 2015 IRP, peak contribution from energy efficiency was estimated using average monthly energy values.

Program Screening

All DSM programs and measures included in Idaho Power's current programs and the forecast have been screened for cost-effectiveness. Cost-effectiveness analyses of DSM forecasts for the 2017 IRP are presented in more detail in *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2016 Annual Report* contains a detailed description of Idaho Power's 2016 energy efficiency programs, along with historical program performance. A complete review of Idaho Power's DSM programs, evaluations, and cost-effectiveness can be found in the

2016 annual report, *Demand-Side Management 2016 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*, which are available on Idaho Power's website at idahopower.com/EnergyEfficiency/reports.cfm.

DSM Program Performance

While the IRP planning process primarily looks forward, recent DSM performance is a good predictor of near-term performance for the 2017 IRP. Accumulated annual savings from energy efficiency investments grow over time based on measure lives of the efficient equipment and measures adopted and installed by customers each year. Additionally, past performance of demand response programs has changed over time as the design and use of the programs have evolved.

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 209 aMW, or over 1.6 million MWh, of reduced supply-side energy production to customers through 2016. Figure 5.1 shows the cumulative annual growth in energy efficiency effects over the 13-year period from 2002 through 2016, along with the associated IRP targets developed as part of the IRP process since 2004.

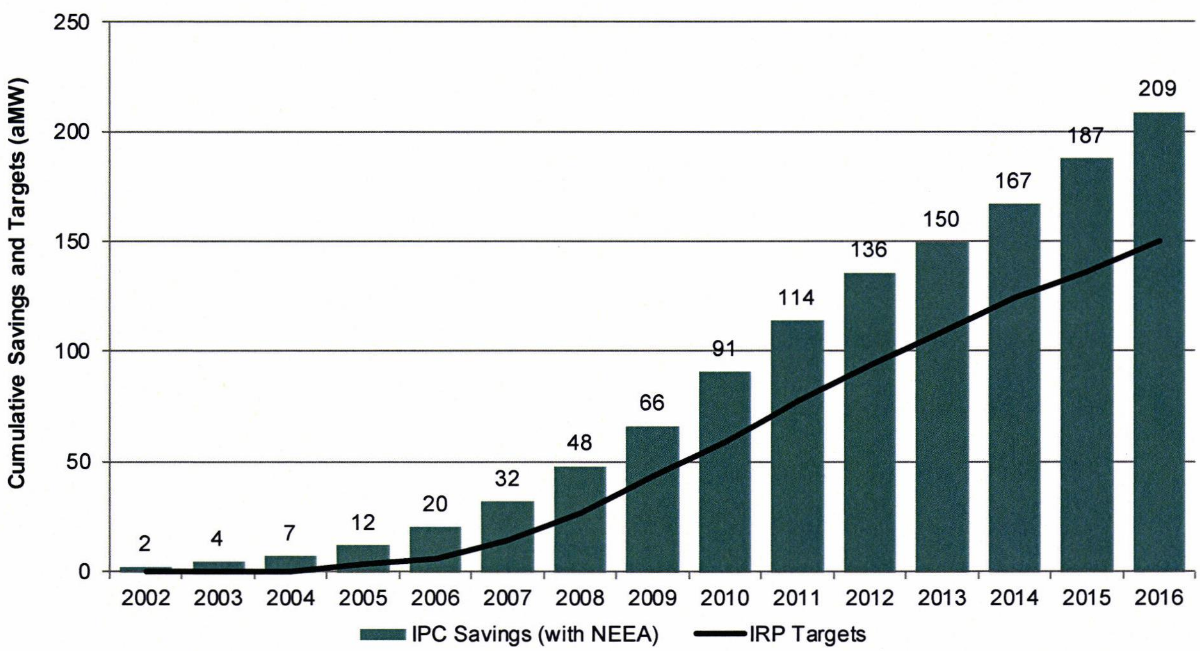


Figure 5.1 Cumulative annual growth in energy efficiency

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 that work together as one resource. Each program targets a different customer class. Table 5.1 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2016 summer season, Irrigation Peak Rewards participants contributed 81 percent of the total potential demand-reduction capacity, or 317 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2016 Annual Report.*

Table 5.1 Demand response programs

Program	Customer Class	Reduction Technology	2016 Total Demand Response Capacity (MW)	Percent of Total 2016 Peak Performance
A/C Cool Credit	Residential	Central A/C	34	9%
Irrigation Peak Rewards	Irrigation	Pumps	317	81%
Flex Peak Program	Commercial, industrial	Various	42	11%
		Total	**392**	

Figure 5.2 shows the historical annual demand response program capacity between 2004 and 2016 along with associated IRP targets between 2006 and 2012 and 2015 through 2016. There were no demand response targets for 2013 to 2014 in the 2013 IRP. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning most the Irrigation Peak Rewards participants to a dispatchable program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity, respectively, from the Irrigation Peak Rewards program, which was not used based on the lack of need and the variable cost to dispatch the program. The reported demand response capacity value was lower in 2013 because of the one-year suspension of both the irrigation and residential programs.

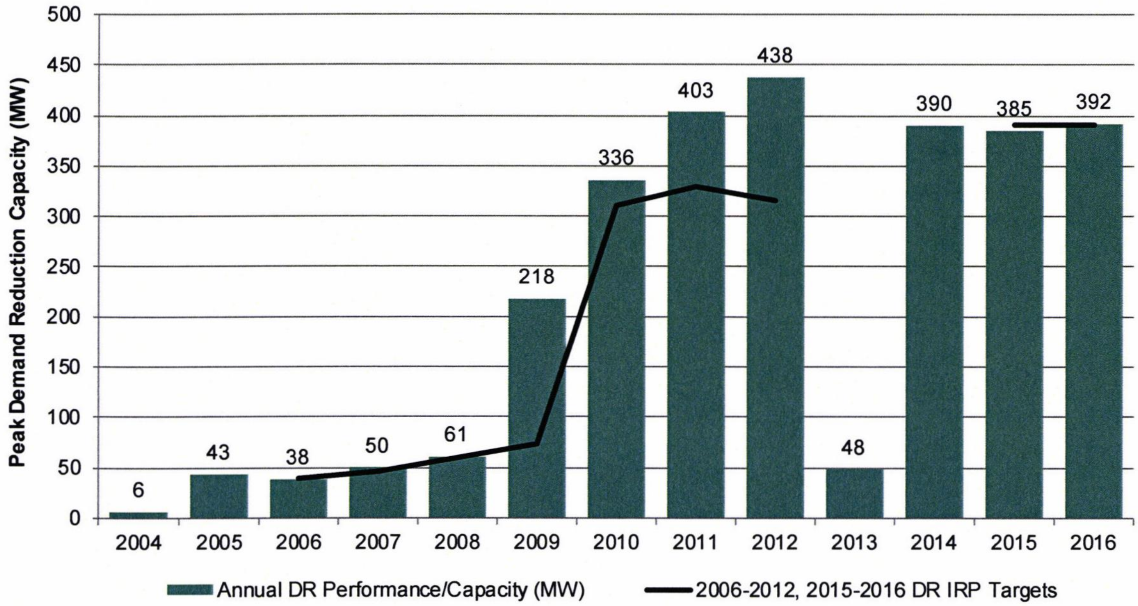


Figure 5.2 Historical annual demand response programs

Committed Energy Efficiency Forecast


Typical irrigation pivots

For the 2017 IRP, Applied Energy Group (AEG) was retained to update the previous study prepared for the 2015 IRP and provide an updated 20-year comprehensive view of Idaho Power's energy efficiency potential.

AEG developed three levels of potential: technical, economic, and achievable. Technical and economic potential are both theoretical limits to efficiency savings, while achievable savings become the planning case forecast for energy efficiency in the 2017 IRP. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. The three levels of potential are described below.

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

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, AEG applies the total resource cost (TRC) test for cost-effectiveness, which compares lifetime energy and capacity benefits to the incremental cost of the measure. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential considers market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes 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 economic potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The market characterization study bundles industries and building types into homogenous groupings. Idaho Power's special-contract customers were treated outside of the potential study model. Forecasts for these unique customers, who tend to be very active in efficiency, were based on the combined customer group's history of participation along with the near-term projected projects.

AEG provides the annual savings potential forecast to Idaho Power in gigawatt-hours (GWh), where it is converted to hourly, then monthly, average energy reduction (aMW) to compare with supply-side resources for the IRP analysis. The savings are shaped by end-use load shapes that spread the forecasted savings across all hours of the year. The load shapes used to allocate savings by end use were provided by AEG as part of the study deliverables. All reported energy efficiency and demand response forecasts are expressed at generation level and therefore include line losses of 9.6 percent for energy and 9.7 percent for peak demand to account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the meter level.

Table 5.2 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2017 to 2036 in five-year blocks in terms of cumulative average annual energy reduction (aMW) by customer class. Detailed annual forecast values can be found in *Appendix C—Technical Appendix*.

Table 5.2 Total energy efficiency portfolio forecasted effects (2017–2036) (aMW)

Customer Class	2017	2021	2026	2031	2036
Industrial/commercial/special contracts	9	51	105	140	175
Residential	2	14	27	46	66
Irrigation	2	8	16	23	31
Total*	**13**	**73**	**147**	**208**	**273**

*Totals may not add exactly due to rounding.

Table 5.3 shows the 20-year cost-effectiveness summary based on the AEG potential study and preliminary DSM alternative costs. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficient technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings with the DSM preliminary alternative costs.

Table 5.3 Total energy efficiency portfolio cost-effectiveness summary

Customer Class	2036 Load Reduction (aMW)	2036 Peak-Load Reduction (MW)*	Resource Costs ($000s) 20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	66	–	$155,425	$295,479	1.9	6.7
Industrial/commercial/ special contract	176	–	$302,559	$567,923	1.9	3.9
Irrigation	31	–	$81,981	$133,498	1.6	6.7
Total	**273**	**483**	**$539,965**	**$996,900**	**1.8**	**4.8**

*Final peak-reduction estimates were calculated only for the portfolio as a whole.

The completed energy efficiency forecast is included in the IRP planning horizon and the load and resource balance analysis after ensuring all future energy efficiency was properly accounted for and netted out of future loads prior to portfolio analysis. As noted earlier in this chapter, the company's IRP load forecast accounted for all of the accumulated 20-year potential energy efficiency savings, exceeding the AEG-determined potential over the last seven years of the IRP planning period (2030–2036). Portfolios for the IRP were developed based on the assumption that for 2030 to 2036, the amount of energy efficiency in the load and resource balance is the amount accounted for in the company's load forecast, rather than the smaller amount determined by AEG in the potential study. For the energy load and resource balance, the accumulated energy efficiency in the company's load forecast is 300 aMW, rather than the 273 aMW load reduction provided in Table 5.3 above. The accumulated peak-load reduction in the company's load forecast is 531 MW, rather than the 483 MW noted in Table 5.3.

The amount of energy efficiency determined by the DSM potential study to be cost-effective and achievable sets an appropriate and prudent target for energy efficiency for the 2017 IRP; this amount of energy efficiency is included in all analyzed portfolios before all other resources. Idaho Power recognizes that the amount of energy efficiency achieved in practice may ultimately exceed the 2017 IRP target amount as a result of implementation efforts of the company and the Energy Efficiency Advisory Group (EEAG). The achievable potential is in no way considered a ceiling for funding or the company's efforts.

Further, the company recognizes that alternative (or avoided) costs used for the cost-effectiveness evaluation are likely to change in the interim between the 2017 IRP and 2019 IRP as key drivers of these costs (e.g., natural gas price) vary. Thus, it is the company's view that the DSM potential study-determined cost-effective and achievable energy efficiency sets the target for the amount of energy efficiency available in this IRP. This target does not represent a ceiling or finite amount for actual energy efficiency activities. It is emphasized that neither the cost-effectiveness nor the achievability of this target is fixed; both attributes can change following completion of this IRP, and future analysis (e.g., the 2019 IRP) will reflect these changes.

Transmission and Distribution Deferral Benefits Associated with Energy Efficiency

The transmission and distribution (T&D) deferral benefits associated with energy efficiency were determined using all growth projects from Idaho Power's officer-reviewed three-year budget for 2016. Transmission, substation, and distribution projects were represented. The limiting capacity (determined by feeder or transformer) was identified for each project along with the anticipated in-service date, projected cost, peak loading, and projected growth rate.

The forecast for the penetration of energy efficiency was incorporated into the formula. Independent energy efficiency demand reduction forecasts for different rate classes were applied at summer and winter peak. If the adjusted forecast was below the limiting capacity, it was assumed the project could be deferred. The financial savings of deferring the project were then calculated.

The total savings from all the deferrable projects were divided by the total annual energy efficiency reduction forecast over the service area. A sensitivity analysis was conducted with an energy efficiency forecast multiplier of 0 to 10 times the existing forecast. Based on the analysis, a value of $3.76 per kW per year will be used as the T&D deferral value.

Committed Demand Response Forecast

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

Additional Demand Response

As part of the IRP's expressed strategy to set the highest standard for evaluating B2H cost-effectiveness, B2H alternative portfolios include an additional 50 MW of demand response in 25 MW increments in 2021 and 2026. The achievement of this additional 50 MW is reasonable and consistent with the role of demand response as a cost-effective capacity resource available to shift peak loading for a finite number of hours. While the B2H-based portfolios did not include the added demand response for the purpose of focusing the costs and benefits of these portfolios on B2H, the company does not view B2H as precluding the continued evaluation and as-needed expansion of demand response resources.

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6. Transmission Planning

Past and Present Transmission

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

High-voltage transmission lines are vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that serve southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects in the 1950s and 1960s. In the 1970s and 1980s, transmission lines facilitated partnerships in the three coal-fired power plants located in neighboring states that deliver energy to Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its intermittent resources with access to wholesale energy markets.

Idaho Power's transmission interconnections provide economic benefits and improve reliability through the flexibility to move electricity between utilities to serve load and to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience peak loads during the winter; as a result, Idaho Power can purchase energy from the Mid-Columbia energy trading market to meet peak summer load and sell excess energy to Pacific Northwest utilities during the winter and spring. Additional regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers in the following ways:

- The construction of additional resources to serve summer peak load is delayed or avoided.
- Revenue from off-system sales during the winter and spring is credited to customers through the PCA.
- Revenue from others' use of the transmission system is credited to Idaho Power customers.
- System reliability is increased.
- Increased capacity can help integrate intermittent resources, such as wind and solar.

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

Transmission Planning Process

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

Local Transmission Planning

The expansion planning of Idaho Power's transmission network occurs through the biennial local transmission planning (LTP) process which identifies the transmission required to interconnect load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the planned supply-side resources identified in the IRP process, the transmission upgrades identified in the local-area transmission advisory process, the 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 identifying potential resources, potential resource locations, and load-center growth, the required transmission system capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

Idaho Power develops long-term, local-area transmission plans for various load centers within Idaho Power's service area by applying a local-area transmission advisory process. This process uses community advisory committees and is performed every 10 years for each area. The community advisory committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for the full development of the area. The plans account for land-use limits and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for the following load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Eastern Treasure Valley
5. Western Treasure Valley
6. West Central Mountains

Regional Transmission Planning

Idaho Power is active in regional transmission planning through the NTTG. The NTTG was formed in early 2007 to improve the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), Montana–Alberta Tie Line (MATL), and the Utah Associated Municipal Power Systems (UAMPS). Biennially, the NTTG develops a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers.

Interconnection-Wide Transmission Planning

The WECC Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three functions:

1. Oversee data management for the western interconnection.
2. Provide policy and management of the planning process.
3. Guide the analyses and modeling for Western Interconnection economic transmission expansion planning.

In addition to providing the means to model the transmission implications of various load and resource scenarios at an interconnection-wide level, the TEPPC coordinates planning between transmission owners, transmission operators, and regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. WECC activities include resource adequacy analyses and corresponding NERC reporting, transmission security studies, and the transmission line rating process.

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. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between specific southern Idaho load centers. Idaho Power's transmission system and paths are shown in Figure 6.1.

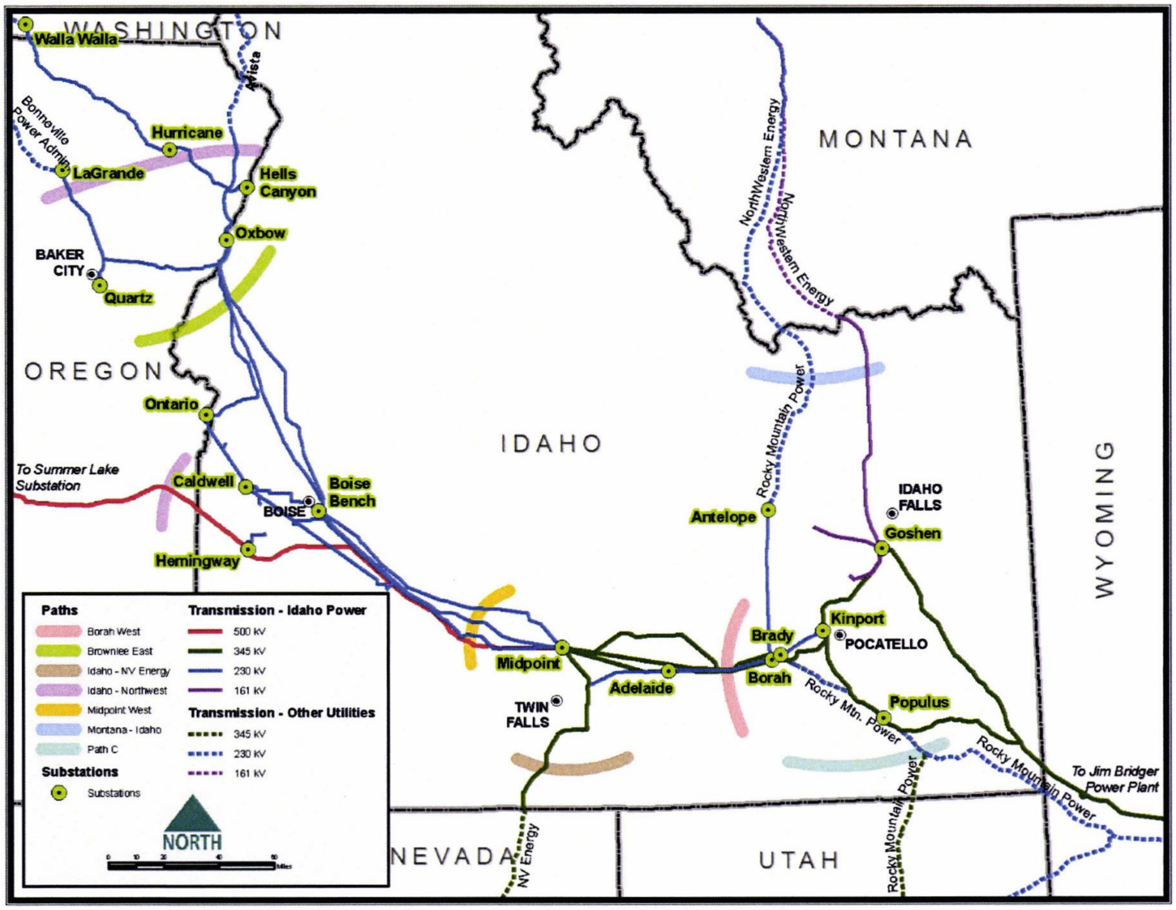


Figure 6.1 Idaho Power transmission system map

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

Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney Substation near Burns, Oregon. The Idaho–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. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's service area.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the

HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Brownlee East Total path.

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the HCC, as well as off-system purchases 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.

Montana–Idaho Path

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

Borah West Path

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

Midpoint West Path

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

Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the North Valmy Power Plant was built in northern Nevada. Idaho Power is allocated 100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns 774 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 is limited by Borah West path capacity constraints.

Idaho–Utah Path

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

Table 6.1 summarizes the import capability for paths impacting Idaho Power operations and lists their total capacity and available capacity; most of paths are completely allocated with no capacity remaining.

Table 6.1 Transmission import capacity

Transmission Path	Import Direction	Capacity (MW)	ATC (MW)*
Idaho–Northwest	West to east	1,200	0
Idaho–Nevada	South to north	262	0
Idaho–Montana	North to south	383	0
Brownlee East	West to east	1,915	Internal Path
Midpoint West	East to west	1,710	Internal Path
Borah West	East to west	2,557	Internal Path
Idaho–Wyoming (Bridger West)	East to west	2,400	86 (Idaho Power Share)
Idaho–Utah (Path C)	South to north	1,250	PacifiCorp Path

* The available transmission capacity (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).

B2H

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

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

The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, 2013, and 2015 IRPs.

The B2H project is a regionally significant project. The project has been identified as producing a more efficient or cost-effective plan in the NTTG's 2007, 2009, 2011, 2013, and 2015 biennial regional transmission plans.[14] NTTG regional transmission plans aim to produce a more efficient or cost-effective regional transmission plan that meets the transmission requirements associated with the load and resource needs of the NTTG footprint.

Additionally, the B2H project is a nationally recognized project. The project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money.[15]

[14] nttg.biz/site/

[15] boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf

Project Participants

In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the B2H project. Table 6.2 shows each party's B2H capacity and permitting cost allocation.

Table 6.2 B2H capacity and permitting cost allocation

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

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to serve eastern Idaho load from the Hemingway Substation. BPA identified six solutions—including two B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publicly announced the preferred solution to be the B2H project. The participation of three large utilities working toward the permitting of B2H further demonstrates the regional significance and regional benefits of the project.

Permitting Update

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), US Forest Service (USFS), Department of the Navy, and ODOE. The federal permitting process is dictated primarily by the *Federal Land Policy Management Act* and *National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On November 25, 2016, BLM published the Final Environmental Impact Statement (EIS). Figure 6.2 shows the proposed transmission line routes included in the Final EIS with the agency preferred route. Idaho Power expects the BLM to issue a Record of Decision (ROD) by summer 2017.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE in February 2013. Idaho Power plans to submit an amended pASC in summer 2017.

Given the ongoing permitting requirements, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2024 or beyond.

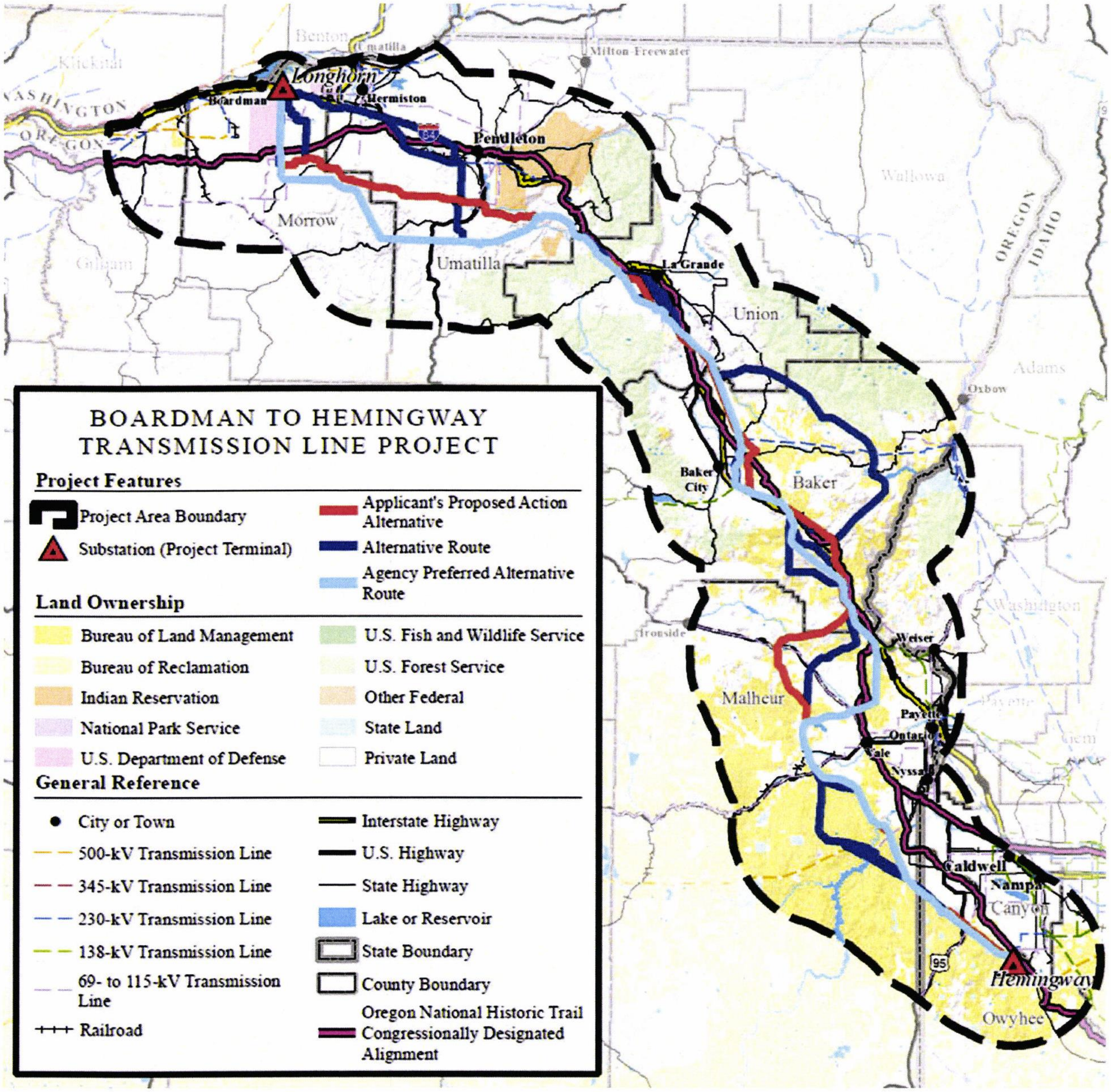


Figure 6.2 B2H routes with the agency-preferred alternative

Activities after BLM ROD

After the BLM issues a ROD and the amended pASC has been submitted to the ODOE and deemed complete, sufficient route certainty will exist to begin preliminary construction activities. These activities include, but are not limited to, the following:

- Geotechnical surveys
- Detailed ground surveys (light detection and ranging [LiDAR] surveys)
- Sectional surveys

- Right-of-way (ROW) activities
- Detailed design
- Construction bid package development

After the Oregon permitting process concludes, construction activities would commence. Construction activities include, but are not limited to, the following:

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

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

B2H Cost Treatment in the IRP

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. However, historically, additional transmission wheeling revenue has not been quantified for a transmission capacity addition. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project.
After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system. In the IRP modeling, the estimated incremental transmission wheeling revenue from non-native load customers was modeled as an annual revenue credit for B2H portfolios.

Northwest Seasonal Resource Availability Forecast

The assessment of regional resource adequacy is part of the regional transmission planning process, and the review of adequacy assessments is useful in understanding the liquidity of regional wholesale electric markets. For the 2017 IRP, Idaho Power has reviewed two recent assessments and their respective characterizations of regional resource adequacy in the Pacific Northwest: 1) the adequacy assessment conducted by the NWPCC Resource Adequacy Advisory Committee (RAAC) and 2) the adequacy assessment conducted by the BPA.

In July 2013, the NWPCC approved a charter for the RAAC, which provided that the RAAC's purpose is to assess power-supply adequacy in the Northwest. Idaho Power has participated in the RAAC since its inception, and also in the NWPCC's Resource Adequacy Forum, which preceded the RAAC.

The NWPCC adopted an adequacy standard used by the RAAC as a metric for assessing resource adequacy. The purpose of the resource adequacy standard is to provide an early warning should resource development fail to keep pace with demand growth. The analytical information generated with each resource adequacy assessment assists regional utilities when preparing their individual IRPs. The statistic used to assess compliance with the adequacy standard is the likelihood of supply shortage, which is commonly known as the loss-of-load probability (LOLP). Under the adequacy standard, the LOLP is held to a maximum level of 5 percent.

The RAAC issued a report in September 2016 on resource adequacy for the 2021 operating year.[16] The 2021 operating year follows the 2020 retirement of 1,330 MW of coal-fired generating capacity at Centralia (Washington) Unit 1 and the Boardman power plant. The RAAC adequacy assessment reports the LOLP for operating year 2021 is 10 percent, and that to maintain resource adequacy at the maximum level of 5 percent the Pacific Northwest needs to add slightly more than 1,000 MW of new capacity. The RAAC also reports that the retirement of approximately 600 MW of coal-fired generating capacity at Colstrip units 1 and 2, currently anticipated for summer 2022, would increase the LOLP to approximately 13 percent if the retirement of the Colstrip units was moved up to earlier than operating year 2021. The adequacy assessment demonstrates Pacific Northwest adequacy concerns in both winter and summer. Winter LOLP exceeds summer LOLP, except for the analysis assuming pre-2021 retirement of Colstrip units 1 and 2, wherein late summer LOLP exceeds winter LOLP. Under both assumptions for Colstrip units 1 and 2, the LOLP in June and July is zero. The RAAC is currently conducting an updated adequacy assessment for the 2022 operating year. Preliminary results of the updated assessment released by the RAAC indicate a lowered LOLP for operating year 2022 of just under 8 percent. A report on the updated adequacy assessment from the RAAC is anticipated in 2017.

BPA annually assesses regional resource adequacy in its Pacific Northwest load and resource study. The BPA assessment accounts for forecast load growth in the Pacific Northwest (including Idaho and Montana), existing generation, planned new generation considered as highly certain, and committed generation retirements. In their assessment, BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly

[16] NWPCC. Pacific Northwest power supply adequacy assessment for 2021. 2016. Document 2016-10. https://www.nwcouncil.org/media/7150591/2016-10.pdf. Accessed on: April 25, 2017.

production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937).

The most recent BPA adequacy assessment report was released in December 2016 and evaluates resource adequacy from 2018 through 2027.[17] Monthly capacity adequacy is analyzed from the perspective of one-hour capacity and 120-hour sustained capacity. In the 2016 assessment, the Pacific Northwest region is projected in 2027 to have summer surpluses from the one-hour perspective in June through the first half of August, then a deficit of nearly 200 MW in the second half of August. From the 120-hour sustained capacity perspective, the Pacific Northwest region is projected in 2027 to have a surplus in June, then to be in deficit for July and August. However, the projected 120-hour deficits in July and the first half of August are less than half those predicted for the winter months, suggesting the addition of sustained capacity needed to address winter deficits would be available as surplus capacity to the summer wholesale market in the region.

The Pacific Northwest was historically characterized as an energy-constrained region, rather than capacity constrained. Load-serving entities could typically serve capacity needs, but during periodic low water conditions may encounter energy constraints. However, over time the region has trended toward becoming capacity constrained, as shown by the RAAC and BPA adequacy assessments. While the regional adequacy assessments suggest potential capacity inadequacies, these inadequacies for both assessments are shifted from the timing of Idaho Power's peak needs. Specifically, the adequacy assessments find summer inadequacies in the region occur in the late summer, by which time demand for energy from Idaho Power's irrigation customers has substantially declined from its late-June through early-July peak. Further, the RAAC adequacy assessment acknowledges that its assessment does not include generating capacity not yet sited or licensed, or generating capacity additions driven by RPS requirements. Known new generating capacity planned by 2021 of about 550 MW, along with RPS requirements in Washington, Oregon, and California, will drive resource expansion. The regional resource adequacy assessments are consistent with Idaho Power's view that expanded transmission interconnection to the Pacific Northwest (i.e., B2H) provides access to a market with capacity for meeting its summer load needs and abundant low-cost energy, and that expanded transmission is critical in a future with automated energy markets (i.e., western EIM) and high penetrations of renewable intermittent resources.

[17] BPA. 2016 Pacific Northwest loads and resources study (2016 white book). https://www.bpa.gov/power/pgp/whitebook/2016/index.shtml. Accessed on: May 19, 2017.

Gateway West

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

Figure 6.3 shows a map of the project identifying the currently 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 20, 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. Per this legislation, the Secretary of the Interior must issue a ROW for Idaho Power's proposed routes for segments 8 and 9 by early August 2017.

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

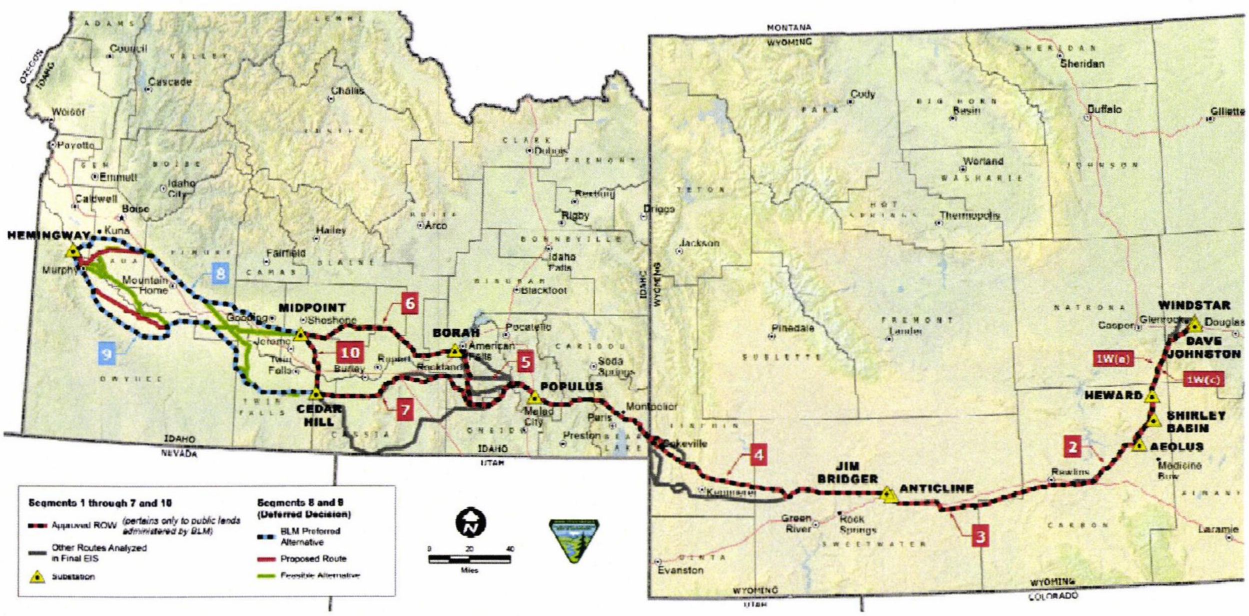


Figure 6.3 Gateway West map

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

1. Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (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.

2. Provide the option to locate future generation resources east of the Treasure Valley.

3. Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation.

4. Help meet the transmission needs of the future, including transmission needs associated with intermittent resources.

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

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

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

Nevada without North Valmy

The Idaho–Nevada transmission path is co-owned by Idaho Power and NV Energy, with Idaho Power having full allocation of northbound capacity and NV Energy having full allocation of southbound capacity. As noted earlier in this chapter, the northbound capacity of the path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

In its evaluation of North Valmy retirement options, Idaho Power has reviewed the potential to import wholesale energy across the Idaho–Nevada transmission path following retirement of North Valmy generating capacity. Idaho Power has principally participated in the Mid-Columbia wholesale power market to the northwest and considers the availability of wholesale energy for import across the Idaho–Nevada path as less certain. In particular, the frequent import of wholesale energy from Nevada is likely to encounter scarcity and/or costly energy. Therefore, while Nevada is not considered a viable source for abundant wholesale energy, it may have potential to source seldom-needed capacity during peak-loading periods. For this reason, Idaho Power is assuming for the 2017 IRP that the retirement of North Valmy generating capacity can be adequately replaced with infrequent wholesale capacity imports across the Idaho–Nevada transmission path.

Idaho Power recognizes the uncertainty of assuming wholesale capacity imports from Nevada can replace North Valmy generating capacity. The viability of the Idaho–Nevada path can be evaluated as the company continues to transition away from coal in a measured and responsible manner. Idaho Power expects to develop greater understanding of the viability of the Idaho–Nevada path with participation in the western EIM beginning in spring 2018. As it continues its evaluation, Idaho Power recognizes the assumption that wholesale capacity imports from Nevada can replace North Valmy generating capacity may prove unfounded, and future IRPs may need to reflect such a change.

Transmission Assumptions in the IRP Portfolios

Transmission lines leading from Danskin Power Plant

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 6.3. The assumptions about the geographic area where supply-side resources are developed determine the transmission upgrades required.

Table 6.3 Transmission assumptions and requirements

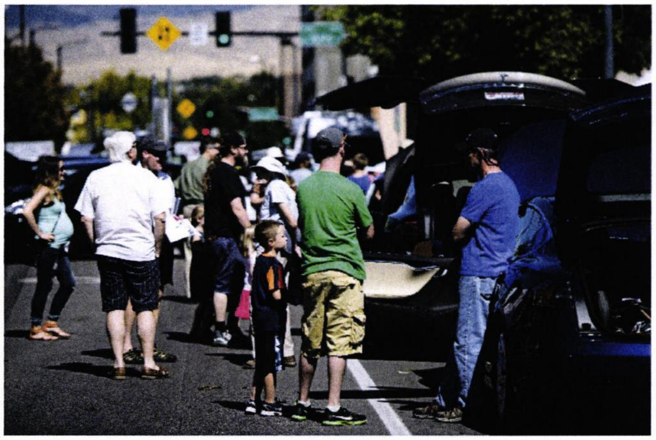
Resource	Capacity	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Biomass indirect—Anaerobic digester	35	Assume distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	Assume $3.5 million of distribution feeder upgrades and $1.2 million in substation upgrades.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Geothermal (binary-cycle)—Idaho	35	Assume Raft River area location; displaces equivalent MW of portfolio resources in same region.	Requires 5-mile 138-kV line to nearby station with new 138-kV substation line terminal bay.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Hydro—Canal drop (seasonal)	1	Assume Magic Valley location connecting to 46-kV sub-transmission or local feeder.	Assume 4 miles of distribution rebuild at $150,000 per mile plus $100,000 in substation upgrades.	No backbone upgrades required.
Natural gas—SCCT frame F class	170	Assume Mountain Home location; displaces	Assume 2-mile 230-kV line required to connect	Assigns pro-rata share for transmission upgrades

Resource	Capacity	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
(Idaho Power's peaker plants use this technology)		equivalent MW of portfolio resources in same region.	to nearby station.	identified for resources east of Boise.
Natural gas—Reciprocating gas engine Wärtsilä 34SG	18	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at 230-kV Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (1x1) F class with duct firing	300	Assume Langley Gulch location; displaces equivalent MW of portfolio resources in same region.	New LGSY–GARNET 230-kV line w/ Garnet 230/138 transformer and Garnet 138-kV tap line. Bundle conductor on the LGSY–CDWL 230-kV line. Reconductor CDWL–LNDN.	No additional backbone upgrades required.
Natural gas—CCCT (1x1) F class with duct firing	300	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2-mile 230-kV line required to connect to nearby station.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (2x1) F class	550	Build new facility south of Boise (assume Simco Road area).	New 230-kV switching station with a 22-mile 230-kV line to Boise Bench Substation and wrap 230-kV Danskin Power Plant to Hubbard line into new station.	Rebuild Rattle Snake to DRAM 230-kV line, rebuild Boise Bench to DRAM 230-kV line, rebuild Micron to Boise Bench 138-kV line.
Natural gas—CHP	35	Assume location in Treasure Valley.	Assume 1-mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—SMR	50	Assume tie into ANTS 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise.	Two 2-mile 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at Antelope Substation.	New parallel 55-mile 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Pumped storage—New upper reservoir and new generation/ pumping plant	100	Assume Anderson Ranch location; displaces equivalent MW of portfolio resources in same region.	18-mile 230-kV line to connect to Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Solar PV—Utility-scale 1-axis tracking	30	Assume Magic Valley location; displaces equivalent MW of portfolio resources in same region.	Assume 1-mile 230-kV line and associated stations equipment.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Wind—Idaho	100	Assume location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region.	Assume 5-mile 230-kV transmission from Midpoint Substation to project site.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.

7. Planning Period Forecasts

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

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



Pedestrians at the Drive Electric Week event in Boise.

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2017 IRP.

Load Forecast

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

Idaho Power has its annual peak demand in the summer, with peak loads driven by irrigation pumps and A/C in June, July, and August. Historically, Idaho Power's growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. Both measures are important in planning future resources and are part of the load forecast prepared for the 2017 IRP.

The expected case (median) load forecasts for peak-hour and average energy (average load) represent Idaho Power's most probable outcome for load growth during the planning period. In addition, Idaho Power prepared two probabilistic load forecasts that address the load variability associated with abnormal weather trends. The 70^{th}-percentile and 90^{th}-percentile load forecasts were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to variable weather conditions.

The expected case forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*.

For example, the expected annual average system load growth of 0.9 percent (over the period 2017 through 2036) is comprised of a residential load growth of 1.2 percent, a commercial load growth of 0.7 percent, an irrigation load growth of 0.6 percent, an industrial load growth of 0.7 percent, and an additional firm load growth of 0.7 percent.

The number of residential customers in Idaho Power's service area is expected to increase 1.8 percent annually from 444,000 at the end of 2016 to nearly 632,000 by the end of the planning period in 2036. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.2-percent average residential load-growth rate.

Significant factors and considerations that influenced the outcome of the 2017 IRP load forecast include the following:

- The load forecast used for the 2017 IRP reflects the continuing recovery of the service-area economy following a severe recession in 2008 and 2009. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed growth. By 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

- The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflects the impact of additional plant investments and associated variable costs of integrating new resources identified in the 2015 IRP preferred portfolio, including the expected cost to comply with carbon-emission regulations. Compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yields lower future prices. The retail prices are most evident after the first two years of the planning period and can impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

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

- Conservation impacts, including DSM energy efficiency programs and codes and standards, and other naturally occurring efficiencies are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., are treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, occurring as a result of growth in the dairy industry. The irrigation sales forecast is higher also as a consequence of renewed production from high-lift acreage. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to efforts to reduce labor costs.

Weather Effects

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50-percent chance loads will be higher or lower than the expected-case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were analyzed to address load variability due to weather—70th-percentile and 90th-percentile load forecasts. Seventieth-percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth-percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal basis. Over the longer-term, economic conditions, demographic conditions, and changing technologies influence the load forecast.

Economic Effects

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

The number of households in Idaho is projected to grow at an annual rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. The number of households in the Boise City–Nampa MSA is projected to grow faster than the rest of Idaho, at an annual rate of 1.6 percent during the forecast period. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. In addition, the number of households, incomes, employment, economic output, electricity prices, and customer consumption patterns are used to develop load projections.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period. This population increase is included in the load forecast models. Idaho Power also continues to receive requests from prospective large-load customers attracted to southern Idaho's positive business climate and relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The 2017 IRP average annual system load forecast reflects continued improvement in the service-area economy. While economic conditions during the development of the 2015 IRP were positive, the resulting sales forecast was more optimistic than the actual performance experienced in the interim period leading up to the 2017 IRP. The improving economic and demographic variables driving the 2017 forecast are reflected by a positive sales outlook throughout the planning period. However, the 2017 IRP forecast is more moderate, and the growth path is less steep.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 7.1 and Table 7.1 show the results of the three forecasts used in the 2017 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70^{th}-percentile forecast, and a 10-percent probability of load exceeding the 90^{th}-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 0.9 percent over the 2017 through 2036 period.

Idaho Power uses the 70^{th}-percentile forecast as the basis for monthly average-energy planning in the IRP. The 70^{th}-percentile forecast is based on 70^{th}-percentile weather to forecast average monthly load and 95^{th}-percentile average peak-day temperature to forecast monthly peak-hour load.

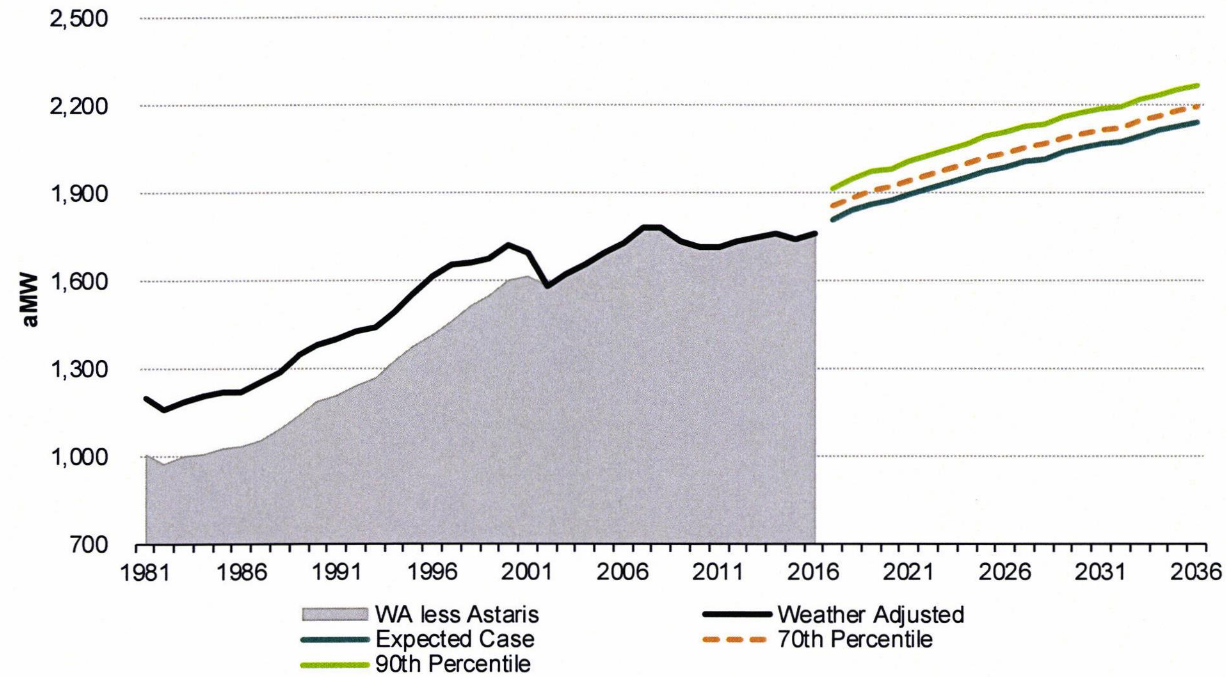


Figure 7.1 **Average monthly load-growth forecast**

Table 7.1 **Load forecast—average monthly energy (aMW)**

Year	Median	70th Percentile	90th Percentile
2017	1,810	1,853	1,917
2018	1,840	1,883	1,948
2019	1,864	1,907	1,973
2020	1,874	1,918	1,984
2021	1,894	1,939	2,006
2022	1,914	1,959	2,027
2023	1,935	1,981	2,049
2024	1,955	2,001	2,070
2025	1,975	2,022	2,092
2026	1,990	2,037	2,108
2027	2,007	2,054	2,126
2028	2,018	2,066	2,137
2029	2,039	2,087	2,160
2030	2,053	2,102	2,175
2031	2,067	2,116	2,190
2032	2,074	2,123	2,197
2033	2,095	2,145	2,220
2034	2,112	2,162	2,237
2035	2,129	2,179	2,255
2036	2,142	2,193	2,269
Growth Rate (2017–2036)	**0.9%**	**0.9%**	**0.9%**

Peak-Hour Load Forecast

As average demands as discussed in the preceding section are an integral component to the load forecast so is the impact of peak-hour demands on the system. Peak-hour forecasts are expressed as a function of the sales forecast, as well as the impact of peak-day temperatures.

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts. Idaho Power uses the 95^{th}-percentile forecast as the basis for peak-hour planning in the IRP. The 95^{th}-percentile forecast is based on the 95^{th}-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,407 MW—was recorded on July 2, 2013, at 4:00 p.m. The system peak-hour load record was nearly matched on June 30, 2015, at 4:00 p.m., when the system peak reached 3,402 MW. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011—the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summer have also had a significant effect on reducing peak demand. The 2017 IRP load forecast projects peak-hour load to grow by over 50 MW per year throughout the planning period in the 95^{th}-percentile case. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance in a manner similar to a supply-side resource.

Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m., matching the previous record peak dated December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summer peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

Figure 7.2 and Table 7.2 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90^{th} percentile, and 95^{th} percentile. The 95^{th}-percentile forecast uses the 95^{th}-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

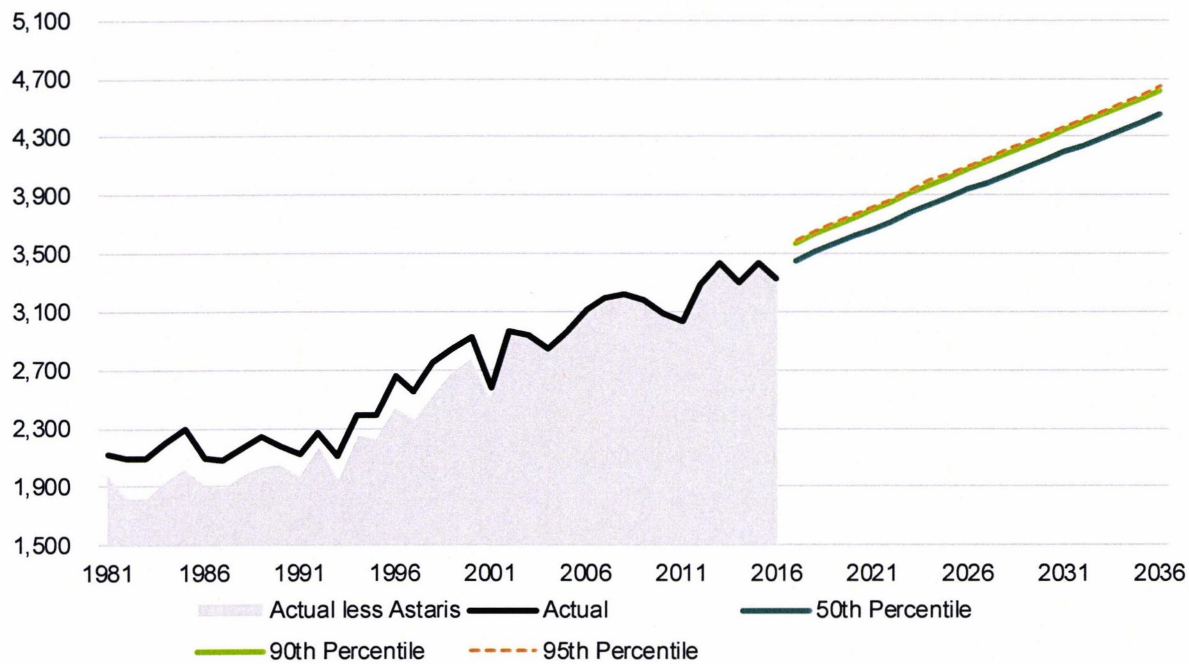


Figure 7.2 **Peak-hour load-growth forecast (MW)**

Table 7.2 **Load forecast—peak hour (MW)**

Year	Median	90th Percentile	95th Percentile
2016 (Actual)	3,327	3,327	3,327
2017	3,446	3,566	3,586
2018	3,508	3,630	3,651
2019	3,567	3,692	3,713
2020	3,618	3,745	3,766
2021	3,668	3,797	3,819
2022	3,722	3,854	3,876
2023	3,778	3,912	3,934
2024	3,838	3,974	3,998
2025	3,888	4,026	4,050
2026	3,937	4,078	4,102
2027	3,989	4,132	4,157
2028	4,042	4,187	4,212
2029	4,092	4,240	4,265
2030	4,141	4,292	4,317
2031	4,192	4,344	4,370
2032	4,239	4,394	4,420
2033	4,289	4,447	4,474
2034	4,342	4,502	4,529
2035	4,395	4,557	4,584
2036	4,449	4,613	4,641
Growth Rate (2017–2036)	**1.4%**	**1.4%**	**1.4%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,446 MW in 2017 to 4,449 MW in 2036—an average annual compound growth rate of 1.4 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.4 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,586 MW in 2017 to 4,641 MW in 2036. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 7.2.

Additional Firm Load

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

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

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 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 (QA); systems integration; and related manufacturing, corporate, and general services. Micron Technology's electricity use is a function of the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly through 2017, then stay flat throughout the remainder of the planning period.

INL

The INL is part of the DOE's complex of national laboratories. The INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2036 for the INL. The forecast calls for loads to increase through 2024, then levelize through the remainder of the forecast period.

Generation Forecast for Existing Resources

Hells Canyon Dam

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak hour load are shown in *Appendix C—Technical Appendix*. The following sections provide a description of Idaho Power's hydroelectric, thermal, and transmission resources and how they are accounted for in the load and resource balance.

Hydroelectric Resources

For the 2017 IRP, Idaho Power continues the practice of using 70th-percentile future streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90th-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90th percentile means streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse-than-median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50th-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2017 IRP is included in *Appendix C—Technical Appendix.*

A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface-water outflow from the river basin. The current water-use practices driving the steady decline over recent years are expected to continue, resulting in declining basin outflows assumed to persist well into the 2030s. The declining basin outflows for this IRP are assumed to continue through the planning period.

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

Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For the peak-hour analysis, a review of historical (2001—2016) operations was performed to estimate the maximum HCC output achieved on an annual basis with 90-percent probability.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April through July runoff period. Figure 7.3 shows historical April through July Brownlee inflow, as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability but do include reductions related to declining base flows in the Snake River. As noted previously in this section, these declines are assumed to continue through the planning period.

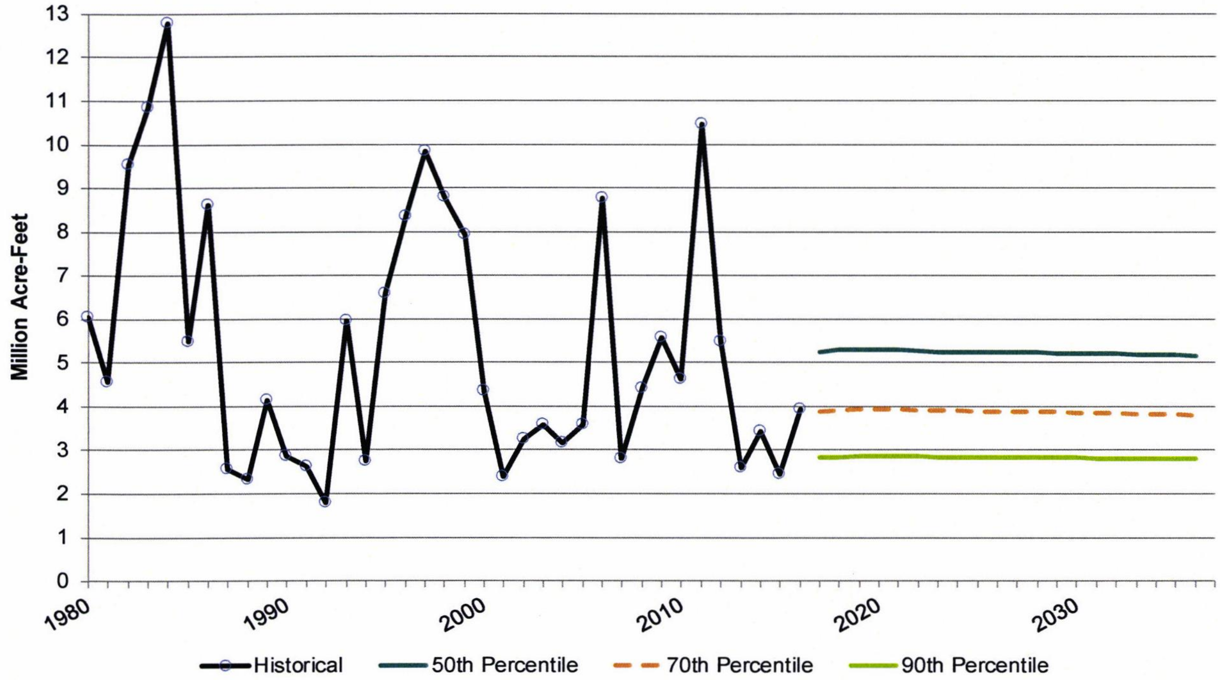


Figure 7.3 Brownlee historical and forecast inflows, April through July

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes too much uncertainty exists to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2017 IRP. Further discussion of climate change and expectations of possible effects on Snake River water supply is available starting on page 64 of the IDACORP Inc. 2016 Form 10-K.

Coal Resources

Idaho Power's coal-fired power plants continue to deliver generating capacity during high-demand periods. However, production of baseload energy from the company's coal plants has declined over recent years, a trend mirrored by coal plants across the region and nation. The decline in baseload energy production is primarily viewed as driven by low natural gas prices and the expansion of renewable generating capacity; because of the low natural gas prices and expanded renewable generating capacity, wholesale electric market prices over recent years have frequently been too low to merit economic dispatch of coal generating capacity. The challenging economics posed by low wholesale electric market prices, particularly when coupled with the need for capital investments for environmental retrofits, have increasingly led owners of coal-fired power plants to evaluate the cost-effectiveness of continued capital expenditure and continued operation. For the 2017 IRP, Idaho Power makes such economic evaluations for the Jim Bridger and North Valmy coal-fired power plants, as described in the following sections.

While coal-fired power plants over recent years are less frequently dispatched for baseload energy production, the projected monthly average energy output from the coal plants in the load and resource balance continues to reflect typical baseload output levels. Because the load and resource balance is a tool for assessing resource adequacy, rather than a forecast of actual resource output, it is appropriate to include the amount of production a resource can produce. With respect to peak-hour output, the capacity load and resource balance includes the coal-fired power plants at their full-rated, maximum dependable capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C—Technical Appendix*.

Boardman Retirement

The 2017 IRP assumes Idaho Power's share of the Boardman plant will not be available for coal-fired operations after December 31, 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with regional-haze regulations on particulate matter, SO_2, and NOx emissions.

North Valmy

The preferred portfolio from the 2015 IRP included retirement of both North Valmy units year-end 2025. The baseline assumption for North Valmy for the 2017 IRP is updated to reflect retirement of Unit 1 year-end 2019 and Unit 2 year-end 2025. The selection of the preferred portfolio for the 2015 IRP, including the 2025 retirement of both North Valmy units, was consistent with strategies to manage exposure to qualitative risk factors. The qualitative risk factors considered in selecting the preferred portfolio for the 2015 IRP included PURPA contract uncertainty, cooperation with NV Energy on retirement planning, B2H execution, and the Clean Power Plan. For the 2017 IRP, these qualitative risks have diminished.

A review of a North Valmy Unit 1 shutdown year-end 2019 determined the likelihood of customer economic benefits associated with the 2019 retirement outweighs the diminished 2015 IRP qualitative risks. The 2017 IRP load and resource balance impact of retiring North Valmy units 1 and 2 in 2019 and 2025, respectively, is mitigated by the assumption that import capacity across the Idaho–Nevada transmission path will be available. For the 2017 IRP, Idaho Power assumed new resources will not be required to replace retiring North Valmy units, as the existing transmission path can satisfy hourly peak needs. Further discussion of the viability of wholesale capacity imports across the Idaho–Nevada transmission path is included in Chapter 6.

Jim Bridger Units 1 and 2 Scenarios

Each of the four Jim Bridger units requires capital investment for retrofitting to comply with regional-haze regulations. The implementation of these regulations is stipulated in a state implementation plan (SIP). PacifiCorp and Idaho Power, as joint owners of the Jim Bridger plant, with the Wyoming Department of Environmental Quality (WDEQ), have developed a plan to implement the regional-haze regulation. The current SIP stipulates installation of SCR retrofitting on Jim Bridger units 3 and 4 in 2015 and 2016, and on units 1 and 2 in 2022 and 2021, respectively. The installation of SCRs on Jim Bridger Units 3 and 4 is complete, and as a baseline assumption, units 3 and 4 are operating resources through the 20-year IRP planning period.

The 2017 IRP analyzes four scenarios related to SCR installation on Jim Bridger units 1 and 2. The scenarios include one in which the SCR investments are made by the required dates in 2021 and 2022, and three alternative scenarios in which units 1 and 2 are retired early at varying dates within the 20-year IRP planning period. The three early-retirement scenarios are analyzed to evaluate the economics of alternatives to SCR installation and to help guide future discussions with the WDEQ in developing a SIP for regional-haze compliance. The four scenarios are as follows:

1. Make the SCR investments and operate Jim Bridger units 1 and 2 through the end of the planning period.
2. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2028 and year-end 2024, respectively.
3. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2032 and year-end 2028, respectively.
4. Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

The four Jim Bridger scenarios are discussed further in Chapter 8.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT. The SCCT units are typically operated during peak-load events in the summer and winter. The monthly average-energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during January, June, July, August, and December and produce approximately 235 aMW of gas-fired generation for the five months. With respect to peak-hour output, the SCCTs are assumed capable of producing an on-demand peak capacity of 416 MW. While the peak dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power's CCCT, Langley Gulch, became commercially available in June 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. Langley Gulch is forecast to contribute approximately 280 aMW, with an on-demand peaking capacity of 300 MW.

Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. For the 2017 IRP, Idaho Power is continuing to use the EIA as the source for the natural gas price forecast. Idaho Power reviewed two natural gas price forecast cases reported by the EIA in the 2016 Annual Energy Outlook (AEO): 1) the Reference Case and 2) the High Oil and Gas Resource and Technology Case. These forecasts are reported by the EIA at Henry Hub, which is an important natural gas distribution hub and pricing point in Louisiana. A graph of historical Henry Hub prices and the reviewed EIA forecasts is provided in Figure 7.4.

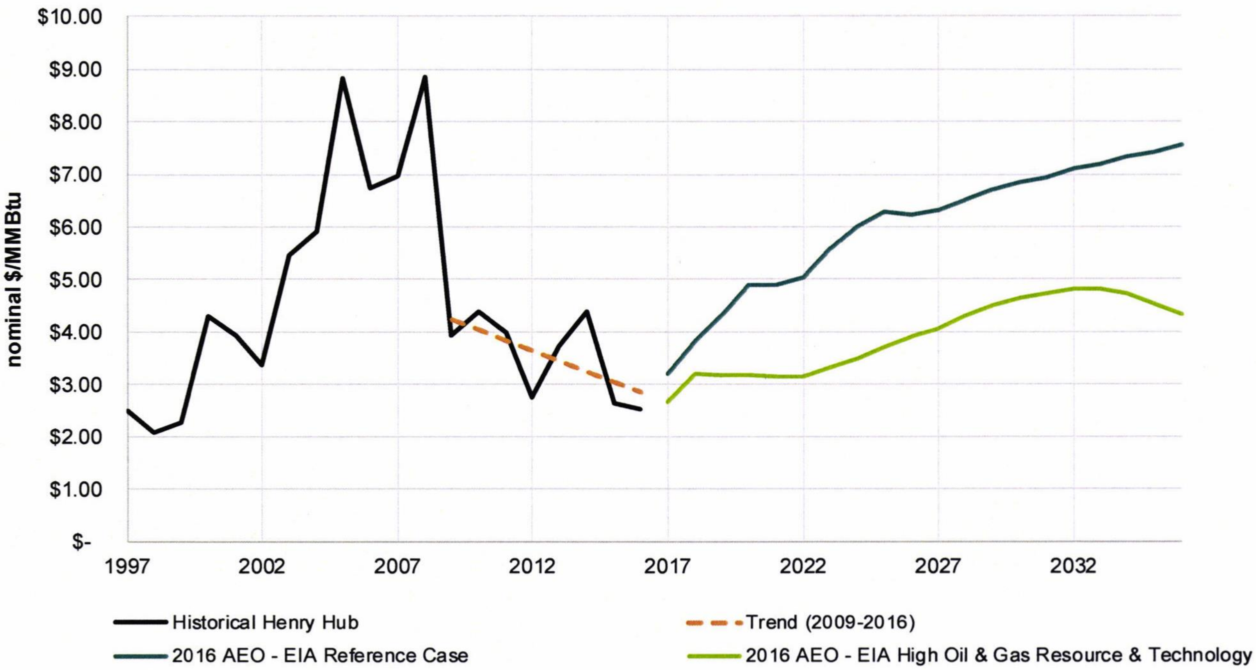


Figure 7.4 Henry Hub natural gas spot price

Importantly, historical Henry Hub prices beginning in 2009 have remained relatively stable and have even trended slightly downward; the illustrated trendline fit to the annual prices for 2009 through 2016 declines at a rate of $0.20 per year. The natural gas price trends since 2009 are highly related to marked expansion of natural gas production from shale. Based on natural gas price trends since 2009 and the coincident expansion of shale gas production, Idaho Power uses the High Oil and Gas Resource and Technology Case as the planning case natural gas price forecast for the 2017 IRP; this case is more consistent with recent price trends than the reference case.

A sensitivity analysis using alternative natural gas price forecasts is described in Chapter 9. The natural gas price is also included as a risk variable in the stochastic risk analysis performed on the IRP resource portfolios.

Idaho Power applies a Sumas basis adjustment and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in *Appendix C—Technical Appendix.*

Analysis of IRP Resources

The electrical energy sector has experienced considerable transformation during the past decade. Variable energy resources, such as wind and solar, have markedly expanded their market penetration during this period, and through this expansion they have affected the wholesale market for electrical energy. The expansion of variable energy resources has also highlighted the need for flexible capacity resources to provide balancing. A consequence of the expanded penetration of variable energy resources is periodic energy oversupply alternating with energy undersupply. Flexible capacity is provided by multiple resources. Dispatchable natural gas-fired generating capacity is commonly designated as cost-effectively providing flexible capacity, particularly during the recent era of low natural gas prices. Transmission resources can be used to provide balancing by the locational moving of energy from parts of the regional grid experiencing oversupply to parts experiencing undersupply. Storage resources can provide balancing by the temporal moving of energy from oversupply periods to undersupply periods. Demand response resources can also provide balancing by temporally moving the demand for energy from periods of undersupply to periods of oversupply.

For the 2017 IRP, Idaho Power continues to analyze resources on the basis of cost, specifically the cost of a resource to provide energy and capacity to the system. The IRP also qualitatively analyzes resources on the basis of their system attributes. In addition to the capability to provide flexible capacity, the system attributes analyzed include the capability to provide dispatchable capacity, non-dispatchable (i.e., coincidental) capacity, and energy. Importantly, energy in this qualitative analysis is considered to include not only baseload-type resources but also resources, such as wind and solar, that provide relatively predictable output when averaged over long periods (i.e., monthly or longer). The resource attribute analysis also designates those resources whose intermittent production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are compared using two cost metrics: levelized cost of capacity (fixed) (LCOC) and levelized cost of energy (LCOE). These metrics are discussed later in this section. The resource cost analysis performed for the IRP assumes Idaho Power incurs all costs of ownership and operation, even for resources for which this ownership paradigm has historically not been typical, such as for geothermal, wind, and solar resources. The assumption that Idaho Power incurs the total resource costs of ownership and operation allows a like-versus-like comparison between resources.

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

The levelized costs for the various resource alternatives analyzed include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs of resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, plant construction costs, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an allowance for funds used during construction (AFUDC) (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio. The B2H resource includes an offsetting cost associated with estimated transmission tariff revenue.

The levelized costs for demand-side resource options include annual program administrative and marketing costs, an annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial effects resulting from the load-reduction programs.

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

LCOC—IRP Resources

The annual fixed revenue requirements in nominal dollars for each resource are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month. Included in these LCOCs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic lives, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. The LCOCs for the potential IRP resources are provided in Figure 7.5. B2H, after netting out transmission tariff revenue, is the lowest-cost resource in terms of LCOC. Other resources among those having a lower LCOC include demand response, reciprocating gas engines, and SCCTs.

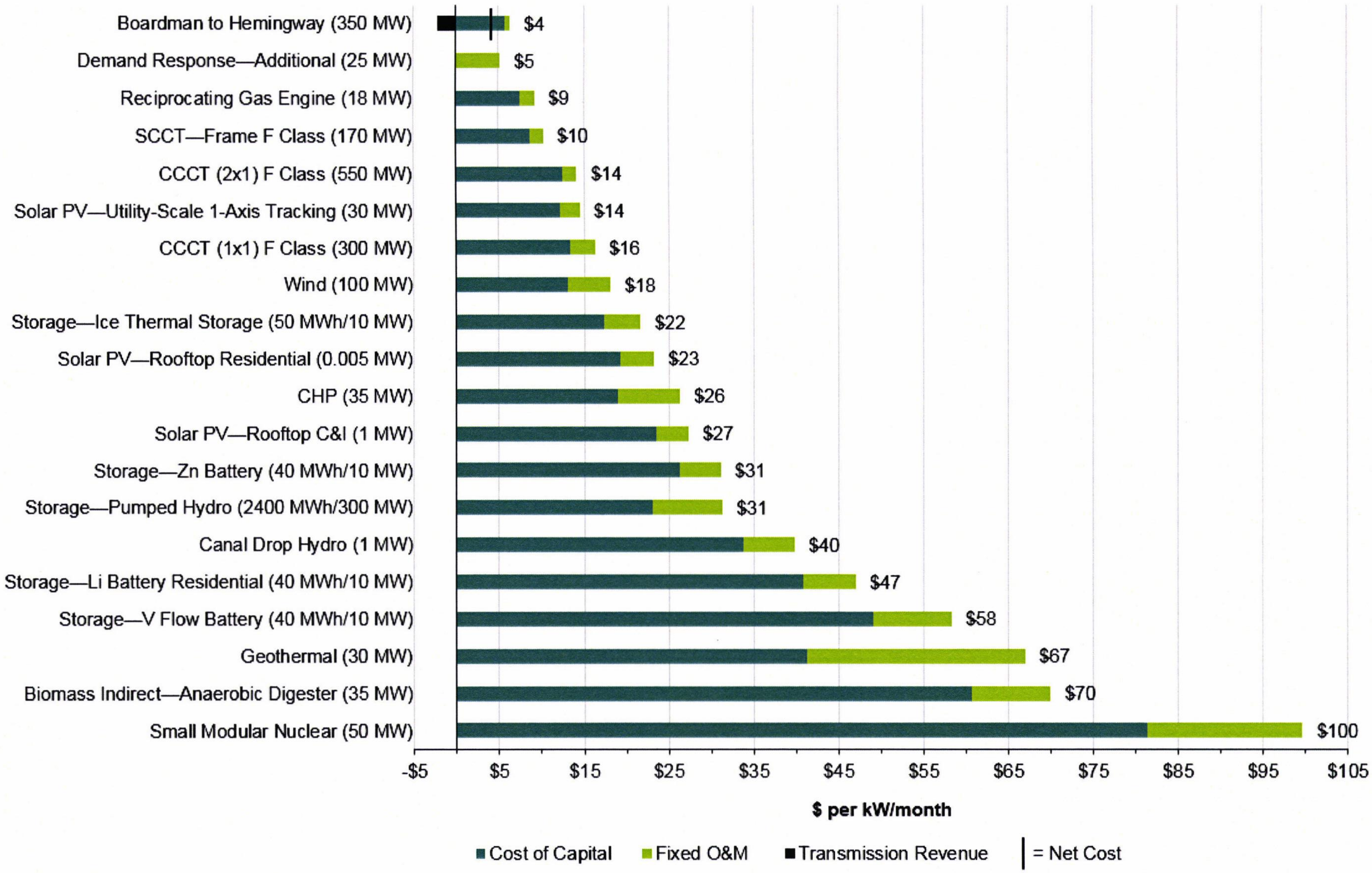


Figure 7.5 **Levelized capacity (fixed) costs**

LCOE—IRP Resources

Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low (or zero) operating costs. The LCOE metric represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource. The nominal LCOE assuming the expected capacity factors for each resource is shown in Figure 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, integration costs, and wholesale energy for transmission and storage resources. Variable costs are offset by transmission tariff revenue for B2H, steam sales for CHP, and RECs for renewable-qualifying resources. B2H is the lowest-cost energy resource, followed by energy efficiency and natural gas-fired generation (CCCT).

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 similar to 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 as a result of spreading resource fixed costs over more MWh. Conversely, lower capacity-factor assumptions reduce the MWh over which resource fixed costs are spread, resulting in a higher LCOE.

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

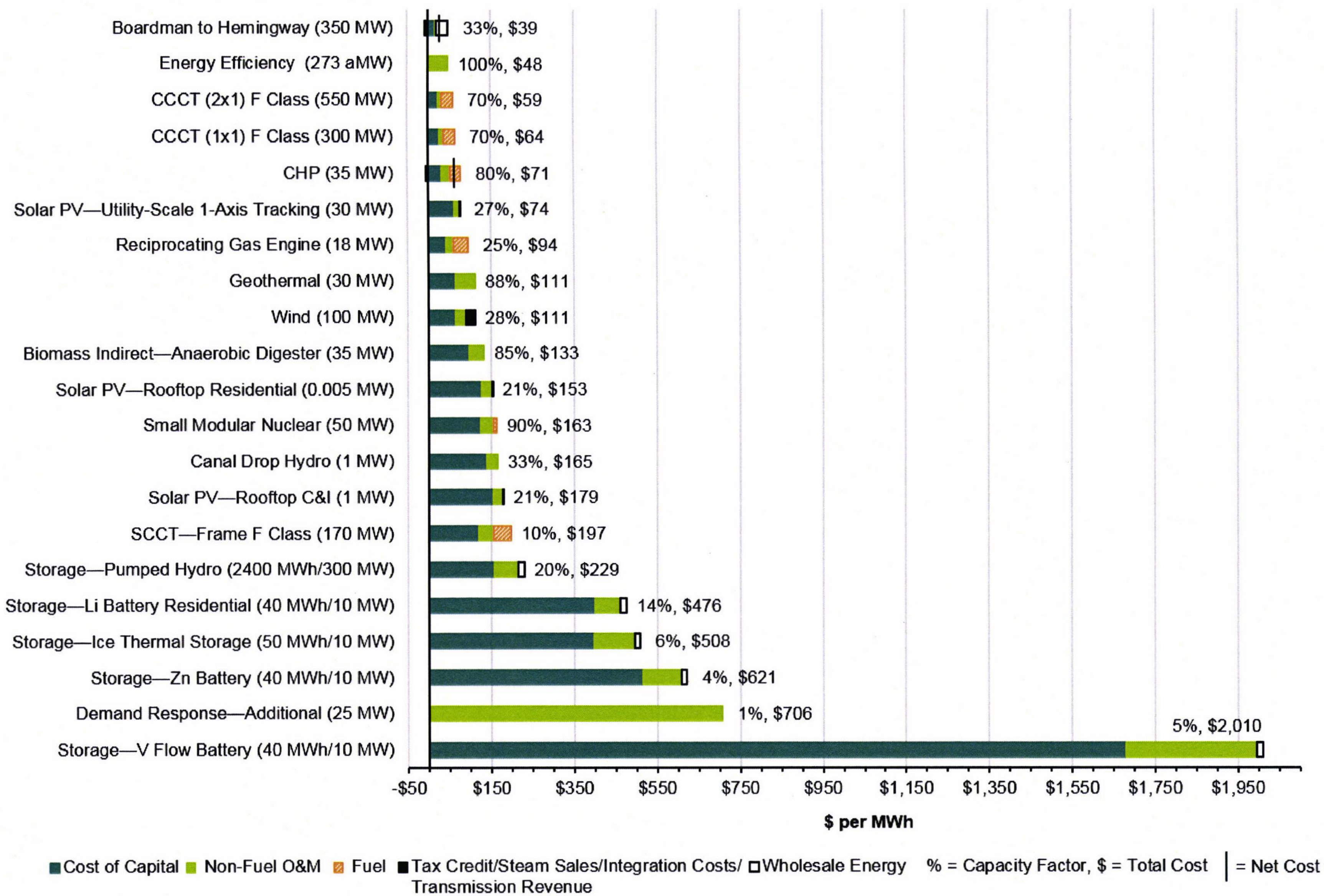


Figure 7.6 **LCOE (as stated capacity factors)**

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 or qualities to the power system. For the LCOC metric, this critical distinction arises because of differences for some resources between *installed* capacity and *on-peak* capacity. Specifically, for intermittent renewable resources, an installed capacity of 1 kW equates to an on-peak capacity of less than 1 kW. For example, wind is estimated to have an LCOC of $18 per month per kW of installed capacity.[18] However, assuming wind delivers on-peak capacity equal to 5 percent of installed capacity, the LCOC ($18/month/kW) converts to $360 per month per kW of on-peak capacity.

For the LCOE metric, the critical distinction between resources arises because of differences for some resources with respect to the timing at which MWh are delivered. For example, wind and geothermal have effectively equivalent LCOEs. However, the energy output from geothermal generating facilities tends to be delivered in a steady and predictable manner, including relatively dependably during peak-loading periods. Conversely, wind tends to less dependably deliver during the high-value peak-loading periods; in effect, the energy delivered from wind tends to be of lesser value than that delivered from geothermal, and because of this difference caution should be exercised when comparing LCOEs for these resources.

In recognition of differences between resource attributes, potential IRP resources for the 2017 IRP are classified based on their attributes or qualities. The following resource attributes are considered in this analysis:

- *Intermittent renewable*—Renewable resources, such as wind and solar, characterized by intermittent output and causing an increased need for resources providing balancing or flexibility
- *Dispatchable capacity-providing*—Resources that can be dispatched as needed to provide capacity during periods of peak-hour loading or to provide output during generally high-value periods
- *Non-dispatchable (coincidental) capacity-providing*—Resources whose output tends to naturally occur with moderate likelihood during periods of peak-hour loading or during generally high-value periods

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

- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from intermittent renewable resources
- *Energy-providing*—Resources producing relatively predictable energy when averaged over long time periods (i.e., monthly or longer).

Table 7.3 provides classification of potential IRP resources with respect to the above attributes. The table also provides cost information as graphed previously and the estimated size potential and scalability for each resource.

Table 7.3 Resource attributes

Resource	Intermittent Renewable	Dispatchable Capacity-Providing	Non-Dispatchable (Coincidental) Capacity-Providing	Balancing/ Flexibility-Providing	Energy-Providing	LCOE ($/MWh)	LCOC ($/kW/Month)	Size Potential
Biomass Indirect—Anaerobic Digester		✓			✓	$133	$70	Scalable up to about 50 MW
B2H		✓		✓	✓	$39	$4	(200 Oct–March, 500 April–Sep)
Canal Drop Hydro		✓			✓	$165	$40	Scalable up to about 50 MW
CCCT (1x1)		✓		✓	✓	$64	$16	300-MW increments
CCCT (2x1)		✓		✓	✓	$59	$14	550-MW increments
CHP		✓			✓	$71	$26	Scalable up to about 50 MW
Demand Response		✓				$706	$5	Scalable up to achievable MW
Energy Efficiency			✓		✓	$48	N/A	Scalable up to achievable MWh
Geothermal		✓			✓	$111	$67	Scalable up to about 50 MW
Reciprocating Gas Engine		✓		✓	✓	$94	$9	18-MW increments
SCCT—Frame F Class		✓		✓		$197	$10	170-MW increments
Small Modular Nuclear		✓			✓	$163	$100	50-MW increments
Solar PV—Rooftop Commercial & Industrial	✓		✓		✓	$179	$27	Scalable
Solar PV—Rooftop Residential	✓		✓		✓	$153	$23	Scalable
Solar PV—Utility-Scale 1-Axis Tracking	✓		✓		✓	$74	$14	Scalable
Storage—Ice Thermal Storage		✓				$508	$22	Scalable
Storage—Lithium Battery Residential		✓		✓		$476	$47	Scalable
Storage—Pumped Hydro		✓		✓	✓	$229	$31	Scalable beyond about 100 MW
Storage—V Flow Battery		✓		✓		$2,010	$58	Scalable
Storage—Zinc Battery		✓		✓		$621	$31	Scalable
Wind	✓				✓	$111	$18	Scalable

IRP Resources and Portfolio Design

As described in the following chapter, the portfolio design for the 2017 IRP focuses on evaluating two key resource actions: the capital investment in environmental retrofits at Jim Bridger units 1 and 2, and the B2H transmission line. This portfolio design allows the 2017 IRP resource portfolios to be composed of resources that most cost competitively test the key resource actions while providing the necessary system attributes to ensure continued reliability. Based on Idaho Power's assessment of resource costs and resource attributes, the analysis of IRP resource portfolios containing natural gas-fired generating capacity (reciprocating engines and CCCTs), expanded demand response, and single-axis tracking solar PV is consistent with the portfolio design objectives of the 2017 IRP.

Idaho Power recognizes that resources attaining modest market penetration to date, particularly electrochemical energy storage technologies (i.e., battery technologies), may become increasingly cost competitive and in future IRPs outcompete natural gas-fired generating capacity. Idaho Power values the discussions held during IRPAC meetings related to emerging technologies and understands that the analysis of a variety of resource technologies, supply- and demand-side, is vital to long-term planning. The focused portfolio design of the 2017 IRP permits the development of portfolios containing resources demonstrated by today's analysis to be most cost competitive.

T&D Deferral Benefit Associated with DERs

The T&D deferral benefits associated with solar distributed energy resources (DER) were discussed at the T&D Deferral Workshop on December 19, 2016. The main considerations in determining the potential for solar DERs to defer T&D investments were discussed. Idaho Power performed a preliminary analysis to determine locations where solar DERs could result in an asset replacement deferral opportunity.

Several criteria were considered to determine viable candidates for asset deferral:

- Summer-peaking assets
- Peak loads that occur before 4:00 p.m.
- Assets that have a use factor at peak greater than or equal to 90 percent
- Load growth rate
- Cost of alternatives

Only two substation transformers and two feeders in Idaho Power's service area fit the criteria, representing approximately 0.5 percent of the total transformers and feeders.

However, Idaho Power is aware that the rapid decrease in the cost of solar PV and energy storage may provide future opportunities for asset replacement deferral. Idaho Power will continue to look for opportunities where DERs may result in cost-effective asset replacement deferral opportunities in the next few years.

Load and Resource Balance

Idaho Power assumes drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources while using the conservative water and load conditions is considered comparable to requiring a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for generation from all the company's existing resources and planned purchases. For the 2017 IRP, load and resource balances were developed for each of the four scenarios for Jim Bridger units 1 and 2. A baseline assumption in the load and resource balances is the early retirement of Valmy units 1 and 2 in 2019 and 2025, respectively. North Valmy units are assumed to be replaced with market purchases imported across the Idaho–Nevada path. Each Jim Bridger scenario will include a load and resource balance using average monthly energy planning assumptions and peak-hour planning assumptions.

Average-energy surpluses and deficits are determined using 70th-percentile water and 70th-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity.

Peak-hour load deficits are determined using 90th-percentile water and 95th-percentile peak-hour load conditions. The hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

All load and resource balances include the following:

- Existing demand reduction due to the demand response programs and the forecast effect of existing energy efficiency programs.
- Expected generation from all Idaho Power-owned resources. The Boardman coal plant has a planned retirement date of 2020. Additionally, the 2017 IRP includes a baseline assumption for the early retirement of Valmy Unit 1 at the end of 2019 and Valmy Unit 2 at the end of 2025.

- Firm Pacific Northwest import capability, including import capacity over the Idaho–Nevada path. The northbound capacity of this line has historically been fully subscribed with Idaho Power's share of energy from the North Valmy generation plant. The load and resource balance scenarios do not include the import capacity from the B2H transmission line or the Gateway West transmission line.
- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. The agreement with Elkhorn Valley Wind expires at the end of 2027, and a replacement contract is not contemplated. The agreement with Raft River Geothermal expires at the end of 2033 and is expected to be replaced. The agreement with Neal Hot Springs does not expire within the planning period.
- Existing PURPA projects and contracts. The 2017 IRP forecast includes all contracts completed by December 9, 2016. Since that time, one biomass project with a nameplate of 5 MW has been added and is scheduled to come on-line in 2018. Idaho Power assumes all PURPA contracts, except for wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the replacement contracts are negotiated. Wind projects are not expected to be renewed. Currently, 627 MW of wind are under PURPA contract, and contract expirations begin in October 2025. By February 2033, the total wind under contract drops to 130 MW and remains at that level through the end of the planning period.

At times of peak summer load, Idaho Power is using all ATC from the Pacific Northwest. If Idaho Power encountered a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Idaho Power's customers reach a maximum energy demand in the summer. From a resource adequacy perspective, July has historically been the month during which Idaho Power's system is most constrained. Based on projections for the 2017 IRP, July is likely to remain the most resource-constrained month. Table 7.4 provides the monthly average energy deficits, and Table 7.5 provides the monthly peak-hour deficits for July for each of the Jim Bridger futures considered in the 2017 IRP. Darker shading in the tables corresponds with larger deficits, which occur more in later years and begin earlier with the retirement of units 1 and 2 in 2021 and 2022, respectively. Surplus positions are not specified in the tables. Because no deficits exist prior to 2023, the tables include data only for the period 2023 to 2036.

Table 7.4 **July monthly average energy deficits (aMW) by Bridger coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)**

Energy Deficits (aMW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	0	0	0	0	(9)	(80)	(107)	(173)	(200)	(226)	(256)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	0	(11)	(41)	(105)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	0	0	0	(143)	(177)	(248)	(276)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2021, 2022	0	(16)	(38)	(180)	(209)	(273)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)

Note: Darker shading indicates increasing deficit values.

Table 7.5 **July monthly peak-hour capacity deficits (MW) by Bridger coal future with existing and committed supply- and demand side resources (90th-percentile water and 95th-percentile load)**

Capacity Deficits (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	(34)	(94)	(159)	(222)	(282)	(346)	(399)	(464)	(521)	(576)	(635)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	(152)	(210)	(270)	(335)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	(34)	(94)	(159)	(397)	(458)	(521)	(574)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2021, 2022	(213)	(275)	(328)	(386)	(445)	(510)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)

Note: Darker shading indicates increasing deficit values.

8. Portfolios

Portfolio Design

Idaho Power designed the portfolio analysis for the 2017 IRP with the objective of informing the IRP's Action Plan with respect to two key resource actions: 1) SCR investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively, and 2) the B2H transmission line. To achieve this objective, the portfolio design consisted of four Jim Bridger SCR investment scenarios, with three resource portfolios formulated within each scenario, resulting in 12 resource portfolios. The SCR investment scenarios study a range of early retirement scenarios at Jim Bridger units 1 and 2 versus a scenario in which the SCR investments are made. The three resource portfolios formulated within each SCR investment scenario include one B2H-focused portfolio and two B2H alternative portfolios. The portfolio design is considered to approximate a controlled experiment isolating two key factors: 1) the cost-effectiveness of making the SCR investments versus practicable early retirement alternatives and 2) the cost-effectiveness of B2H in meeting resource needs versus practicable resource alternatives. This type of portfolio design is also described as a factorial experimental design. Further discussion of the portfolio design is provided in Chapter 1 and at the end of this chapter.

To analyze the SCR investments for Jim Bridger, four scenarios were analyzed:

1. *Scenario* 1—Install SCRs and operate Jim Bridger units 1 and 2 through the end of the planning period.
2. *Scenario 2*—Do not make SCR investments and retire Jim Bridger units 1 and 2 at year-end 2028 and year-end 2024, respectively.
3. *Scenario 3*—Do not make SCR investments are retire Jim Bridger units 1 and 2 at year-end 2032 and year-end 2028, respectively.
4. *Scenario 4*—Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

The B2H alternative portfolios within each Jim Bridger SCR investment scenario have similar characteristics: an alternative portfolio containing a mix of solar- and natural gas-powered generating capacity, and a second alternative containing solely natural gas-powered generating capacity. Demand response capacity is also added to the B2H alternative portfolios in two steps in the early- to mid-2020s. The supply- and demand-side resources composing the B2H alternative portfolios set the highest standard for B2H economics based on current costs. The portfolio design objective is to determine whether a B2H-based portfolio can be outperformed based on current cost estimates of alternative resources. The resources judged to practicably set the highest standard for B2H cost-effectiveness included expanded demand response, flexible capacity-providing natural gas-fired reciprocating engines, single-axis solar

PV, and natural gas-fired CCCTs. Other potential IRP resources were analyzed and considered for inclusion in portfolios. However, the inclusion of less cost-effective resources would lower the standard for the evaluation of B2H.

Capacity needs require the addition of natural gas-powered generating capacity to the B2H-based portfolios; however, this added generating capacity is relatively small compared to B2H, and the costs and benefits of the B2H-based portfolios are considered primarily driven by B2H as a portfolio element. Detailed portfolio descriptions are provided later in this chapter.

The SCR compliance alternatives considered in this IRP are in recognition of past negotiations between owners of coal-powered generating units, regulators, and other stakeholders that yielded a resolution permitting extended operation in exchange for early unit retirement. Idaho Power views the analyzed compliance alternatives as placeholder assumptions representing negotiated resolutions permitting varying operation extensions. The company does not presuppose extensions will be necessarily negotiated, nor that specific alternatives analyzed in this IRP are more likely outcomes than other possible early retirement dates.

Energy savings achieved from implementing cost-effective energy efficiency programs and measures are included in all portfolios prior to the inclusion of supply-side resources. The forecasted energy savings are based on the assessment performed by AEG for Idaho Power. The AEG assessment and the projected energy savings are discussed in Chapter 5.

Studied Portfolios

The following sections describe the portfolios analyzed for each Jim Bridger scenario. All portfolios are designed to balance forecast load with available or additional resources to eliminate energy and capacity deficits according to the IRP planning criteria described in Chapter 7. The energy and capacity deficits for the Jim Bridger scenarios are also provided in Chapter 7.

Jim Bridger Scenario 1

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are made and Jim Bridger units 1 and 2 are operable through the end of the planning period. P1 is the B2H-based portfolio. P2 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity. The reciprocating engine generating capacity of P2 is considered to provide the flexible capacity necessary to reliably integrate the solar-powered capacity of the portfolio. The single-axis solar PV generating capacity is assumed to deliver peak-hour capacity equal to 51.3 percent of installed (AC) nameplate capacity. The analysis supporting the assumed peak-hour capacity for solar-powered PV generating capacity is discussed in Chapter 4. P3 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P2 and P3 include added demand response capacity developed in two steps in 2021 and 2026.

P1

Table 8.1 P1 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2034	Reciprocating engines	36	36
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total	**644**	**644**

Table 8.2 P1 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	144

P2

Table 8.3 P2 timeline

Date	Resource	Installed Capacity	Peak-Hour Capacity
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	25	13
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	50	26
2029	Reciprocating engines	36	36
2029	Single-axis solar PV	50	26
2030	Reciprocating engines	36	36
2030	Single-axis solar PV	50	26
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	50	26
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	35	18
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	60	31
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	45	23
2035	Reciprocating engines	36	36
2035	Single-axis solar PV	40	21
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	45	23
	Total*	**860**	**643**

*Includes demand response

Table 8.4 P2 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	450
Natural gas	360

P3

Table 8.5 P3 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	54	54
2028	Reciprocating engines	54	54
2029	Reciprocating engines	72	72
2030	Reciprocating engines	54	54
2031	CCCT (1x1)	300	300
2036	Reciprocating engines	54	54
	Total*	**638**	**638**

*Includes demand response

Table 8.6 P3 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	588

Jim Bridger Scenario 2

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are permitted to operate through 2028 and 2024, respectively. Within this scenario, P4 is the B2H-based portfolio. P5 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including a 300 MW CCCT. P6 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P5 and P6 include added demand response capacity developed in two steps in 2021 and 2026.

P4

Table 8.7 P4 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2029	Reciprocating engines	72	72
2030	Reciprocating engines	72	72
2031	Reciprocating engines	54	54
2032	Reciprocating engines	54	54
2033	Reciprocating engines	72	72
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	36	36
	Total	**968**	**968**

Table 8.8 P4 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	468

P5

Table 8.9 P5 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2025	Reciprocating engines	54	54
2025	Single-axis solar PV	140	72
2026	Demand response	25	25
2026	Reciprocating engines	18	18
2026	Single-axis solar PV	35	18
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	45	23
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	55	28
2029	Reciprocating engines	300	300
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	55	28
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	40	21
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	55	28

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	45	23
2035	Reciprocating engines	36	36
2035	Single-axis solar PV	25	13
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	25	13
	Total*	**1,230**	**977**

*Includes demand response

Table 8.10 P5 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	520
Natural gas	660

P6

Table 8.11 P6 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2025	Reciprocating engines	126	126
2026	Demand response	25	25
2026	Reciprocating engines	36	36
2027	Reciprocating engines	72	72
2028	Reciprocating engines	54	54
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	72	72
2032	Reciprocating engines	54	54
2033	Reciprocating engines	54	54
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total*	**980**	**980**

*Includes demand response

Table 8.12 Resource P6 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	930

Jim Bridger Scenario 3

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are permitted to operate through 2032 and 2028, respectively. Within this scenario, P7 is the B2H-based portfolio. P8 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including two 300-MW CCCTs. P9 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P8 and P9 include added demand response capacity developed in two steps in 2021 and 2026.

P7

Table 8.13 P7 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2031	Reciprocating engines	36	36
2032	Reciprocating engines	36	36
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total	**980**	**980**

Table 8.14 P7 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	480

P8

Table 8.15 P8 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	25	13
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	50	26
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	50	26

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	35	18
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	18	18
2035	Single-axis solar PV	55	28
2036	Reciprocating engines	18	18
2036	Single-axis solar PV	60	31
	Total*	**1,105**	**972**

*Includes demand response

Table 8.16 P8 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	275
Natural gas	780

P9

Table 8.17 P9 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	54	54
2028	Reciprocating engines	54	54
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	72	72
2032	Reciprocating engines	54	54
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	36	36
2036	Reciprocating engines	54	54
	Total*	**974**	**974**

*Includes demand response

Table 8.18 P9 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	924

Jim Bridger Scenario 4

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are retired on their respective compliance dates of year 2022 and year-end 2021. Within this scenario, P10 is the B2H-based portfolio. P11 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including two 300-MW CCCTs. P12 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P11 and P12 include added demand response capacity developed in two steps in 2021 and 2026.

P10

Table 8.19 P10 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2023	Reciprocating engines	216	216
2024	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2032	Reciprocating engines	54	54
2033	Reciprocating engines	54	54
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	36	36
	Total	**968**	**968**

Table 8.20 P10 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	468

P11

Table 8.21 P11 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2023	Reciprocating engines	108	108
2023	Single-axis solar PV	155	80
2024	Reciprocating engines	36	36
2024	Single-axis solar PV	55	28
2025	Reciprocating engines	36	36
2025	Single-axis solar PV	30	15
2026	Demand response	25	36
2026	Reciprocating engines	18	18
2026	Single-axis solar PV	30	15
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	50	26
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	60	31
2029	Reciprocating engines	36	36
2029	Single-axis solar PV	50	26
2030	Reciprocating engines	36	36
2030	Single-axis solar PV	50	26
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	55	28
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	40	21
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	55	28
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	50	26
2035	Reciprocating engines	18	18
2035	Single-axis solar PV	60	31
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	25	13
	Total*	**1,355**	**995**

*Includes demand response

Table 8.22 P11 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	765
Natural gas	540

P12

Table 8.23 P12 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2023	CCCT (1x1)	300	300
2026	Demand response	25	25
2026	Reciprocating engines	36	36
2027	Reciprocating engines	72	72
2028	Reciprocating engines	54	54
2029	Reciprocating engines	72	72
2030	Reciprocating engines	54	54
2031	CCCT (1x1)	300	300
2036	Reciprocating engines	36	36
	Total*	**974**	**974**

*Includes demand response

Table 8.24 P12 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	924

Portfolio Design with Two Factors

The portfolio analysis for the 2017 IRP is described as a factorial design. This type of experimental design allows an analysis isolating on two (or more) factors, each factor having more than one level describing it. The two factors studied in the portfolio analysis with their respective levels are as follows:

- **Factor 1:** Treatment of Jim Bridger units 1 and 2
  - Level 1: Invest in SCRs and operate through 2036
  - Level 2: Retire Unit 1 in 2028 and Unit 2 in 2024 (without investing in SCRs)
  - Level 3: Retire Unit 1 in 2032 and Unit 2 in 2028 (without investing in SCRs)
  - Level 4: Retire Unit 1 in 2022 and Unit 2 in 2021 (without investing in SCRs)

- **Factor 2:** Primary portfolio element(s)
  - Level 1: B2H
  - Level 2: Solar PV/natural gas-fired generation
  - Level 3: Natural gas-fired generation

Table 8.25 provides a matrix of the factorial design with the portfolios corresponding to each factorial combination.

Table 8.25 Factorial design applied to portfolios

	Primary Portfolio Element(s)		
Treatment of Jim Bridger Units 1 and 2	**B2H**	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

Importantly, to validate this design, portfolios must be devised so they can be categorized according to the studied factor levels. For example, P4, P5, and P6 must all include retirement of Jim Bridger units 1 and 2 in 2028 and 2024, respectively. Similarly, P2, P5, P8, and P11 must all be characterized as having solar PV and natural gas-fired generation as their primary portfolio elements. A tabulation of the portfolio analysis results in the form of the factorial design is provided in Chapter 9.

9. Modeling Analysis and Results

Planning Case Portfolio Analysis

Idaho Power evaluated the net present value (NPV) costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to serve customer load using all resources in the portfolio.

The IRP portfolio costs consist of fixed and variable components. The fixed component includes annualized capital costs for new portfolio resources, including transmission interconnection costs for new generating facilities, fixed O&M costs, and return on investment (ROI). Capital costs for new resources are annualized over the resource's estimated economic life. Annualized capital costs beyond the IRP planning window (2017–2036) are not included in portfolio costs.

Portfolios that consider early retirement of coal units include costs for the accelerated recovery of depreciation expenses and accelerated recovery of estimated decommissioning and demolition costs (net of salvage). The costs of coal-retirement portfolios are countered by savings from avoiding future coal plant capital upgrades and fixed operating expenses beyond the early retirement dates, including avoidance of environmental retrofit upgrades where applicable.

Idaho Power uses the AURORA electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data.

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

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results.

Portfolio costs are calculated as the NPV of the 20-year stream of annualized costs, fixed and variable, for each portfolio. The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 9.1 Financial assumptions

Plant Operating (Book) Life	30 Years
Discount rate (weighted average capital cost)	6.74%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	2.10%
Annual property tax escalation rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premium (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.72%

Idaho Power is limiting the CAA Section 111(d) analysis to a state-by-state mass-based approach. Under state-by-state mass-based compliance, CAA Section 111(d) proposed state-specific target reductions are the basis for compliance. Langley Gulch is assumed to be unconstrained. The proposed target reductions are defined in Table 9.2.

Table 9.2 Proposed target reductions for state-by-state mass-based compliance (Idaho Power share)

Affected Source	2022–2024 Target MWh	2025–2027 Target MWh	2028–2029 Target MWh	2030 and Beyond Target MWh
Jim Bridger Below 2012	3,499,795 (-23%)	3,176,356 (-30%)	2,986,317 (-34%)	2,873,560 (-37%)
North Valmy Below 2012	790,247 (-3%)	737,627 (-9%)	715,611 (-12%)	708,848 (-13%)

The planning case natural gas price variable costs, the new resource fixed costs, and the Bridger units 1 and 2 fixed costs are shown in Table 9.3.

Table 9.3 2017 IRP Portfolios, NPV years 2017–2036 ($ x 1,000)

Portfolio Details				Variable Costs			New Resource Fixed Costs			Bridger	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)	Operating (AURORA) (5)	Rank (6)	Relative Difference (7)	Portfolio Fixed Costs (8)	Rank (9)	Relative Difference (10)	Bridger Fixed Costs (11)	Total Fixed + Variable Costs (12) = (5) + (8) + (11)	Lowest Cost Rank (13)	Lowest Cost Relative Difference (14)
P1	SCR invest, B2H, recips	✓		$5,782,181	10	$252,923	$91,266	1	–	$527,249	$6,400,696	4	$64,925
P2	SCR invest, DR, recips, solar			$5,670,820	4	$141,562	$299,436	5	$208,169	$527,249	$6,497,505	6	$161,733
P3	SCR invest, DR, recips, CCCT			$5,731,938	8	$202,679	$271,669	4	$180,403	$527,249	$6,530,856	9	$195,084
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	$5,796,035	11	$266,777	$207,739	2	$116,473	$334,909	$6,338,683	2	$2,912
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	$5,577,721	2	$48,463	$653,937	10	$562,671	$334,909	$6,566,567	10	$230,796
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	$5,729,526	7	$200,267	$443,808	8	$352,541	$334,909	$6,508,242	8	$172,470
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	$5,755,589	9	$226,331	$214,229	3	$122,963	$365,952	$6,335,771	1	–
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	$5,654,210	3	$124,951	$483,362	9	$392,096	$365,952	$6,503,524	7	$167,753
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	$5,701,053	6	$171,794	$415,995	7	$324,729	$365,952	$6,483,000	5	$147,229
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	$5,807,951	12	$278,693	$309,227	6	$217,961	$283,328	$6,400,507	3	$64,736
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	$5,529,258	1	–	$767,183	12	$675,917	$283,328	$6,579,769	11	$243,998
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	$5,689,172	5	$159,914	$699,009	11	$607,743	$283,328	$6,671,510	12	$335,739

Under the planning case natural gas price, P7 has a total fixed and variable 20-year NPV cost of $6,335,771,000 and a lowest cost rank of 1.

Natural Gas Price Sensitivities

The planning case natural gas shown in Table 9.3 reflects a 2017 IRP lower bound of future gas prices. An additional eight natural gas price sensitivities described as 125, 150, 175, 200, 225, 250, 300, and 400 percent of the planning case price were modeled for each of the 12 portfolios. The natural gas price sensitivities represent a phasing-in of the named percentage over the years 2017 to 2026 and the full named percentage escalation for 2027 to 2036.

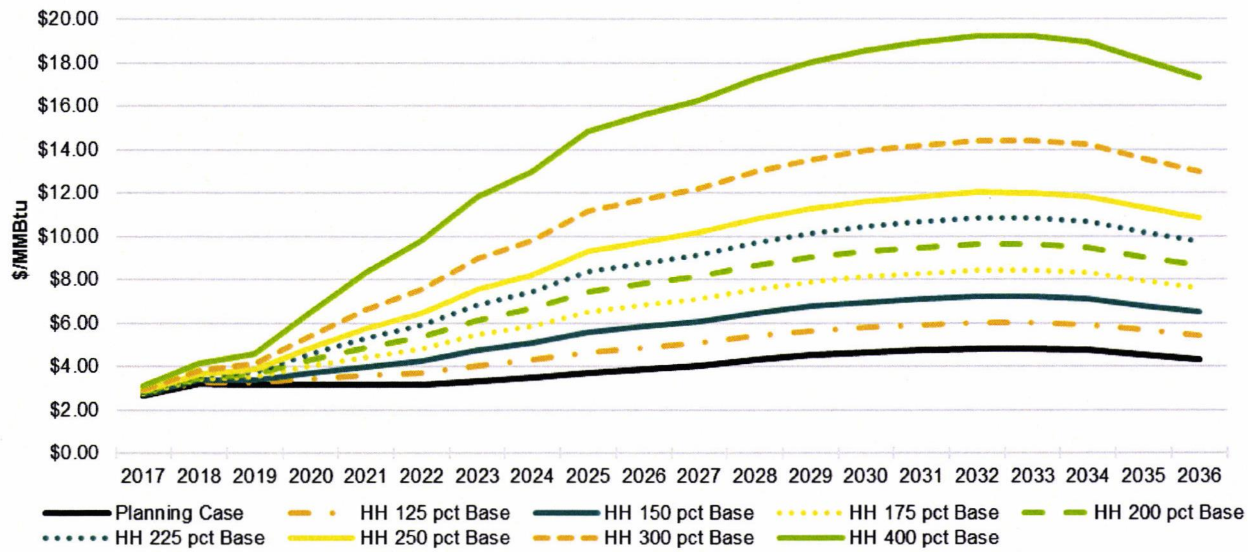


Figure 9.1 Natural gas planning case and eight sensitivities (nominal $)

The relative difference between the NPV of the lowest-cost portfolio under the natural gas price planning case and eight higher natural gas sensitivities, along with the rankings of the 12 portfolios under the nine Natural Gas Price forecasts, are shown in Table 9.4 and Table 9.5.

Table 9.4 Portfolio relative costs under nine natural gas price forecasts

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	$64,925	$159,885	$195,084	$2,912	$227,454	$172,470	–	$166,906	$147,229	$64,736	$238,420	$335,739
HH 125 Percent	$58,058	$142,953	$188,386	$7,376	$207,186	$173,025	–	$155,281	$142,220	$85,896	$229,666	$352,890
HH 150 Percent	$58,142	$129,040	$186,163	$13,472	$183,556	$172,346	–	$143,472	$138,386	$105,611	$212,513	$363,972
HH 175 Percent	$63,386	$120,284	$187,910	$19,377	$162,044	$174,491	–	$133,714	$136,153	$127,583	$196,759	$374,576
HH 200 Percent	$60,514	$102,090	$182,606	$23,856	$135,130	$171,846	–	$119,610	$128,671	$143,776	$174,778	$378,449
HH 225 Percent	$61,904	$92,582	$180,551	$28,388	$110,252	$172,598	–	$106,629	$125,133	$162,122	$154,081	$384,389
HH 250 Percent	$60,720	$76,879	$177,400	$31,620	$84,098	$167,438	–	$93,640	$118,182	$178,368	$130,579	$388,352
HH 300 Percent	$60,257	$50,595	$174,637	$44,796	$35,071	$168,937	–	$72,161	$114,453	$215,307	$89,851	$404,734
HH 400 Percent	$114,023	$50,128	$216,370	$126,783	–	$230,108	$61,658	$82,446	$156,364	$342,022	$61,587	$494,597

Note: Darker shading indicates increasing values.

Table 9.5 Portfolio rankings under nine natural gas price forecasts

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	4	6	9	2	10	8	1	7	5	3	11	12
HH 125 Percent	3	6	9	2	10	8	1	7	5	4	11	12
HH 150 Percent	3	5	10	2	9	8	1	7	6	4	11	12
HH 175 Percent	3	4	10	2	8	9	1	6	7	5	11	12
HH 200 Percent	3	4	11	2	7	9	1	5	6	8	10	12
HH 225 Percent	3	4	11	2	6	10	1	5	7	9	8	12
HH 250 Percent	3	4	10	2	5	9	1	6	7	11	8	12
HH 300 Percent	5	4	10	3	2	9	1	6	8	11	7	12
HH 400 Percent	6	2	9	7	1	10	4	5	8	11	3	12

Note: Darker shading indicates increasing values.

P7 ranks first under eight of the nine natural gas price escalation sensitivities. P5 ranks first under the highest natural gas price sensitivity.

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).

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

1. *Natural gas price*—Natural gas prices follow a log-normal distribution adjusted upward from the planning case gas price forecast, which is shown as the dashed line in Figure 9.2. Natural gas prices are adjusted upward from the planning case to capture upward risk in natural gas prices. The correlation factor used for the year-to-year variability is 0.60, which is based on historic values from 1997 through 2015.

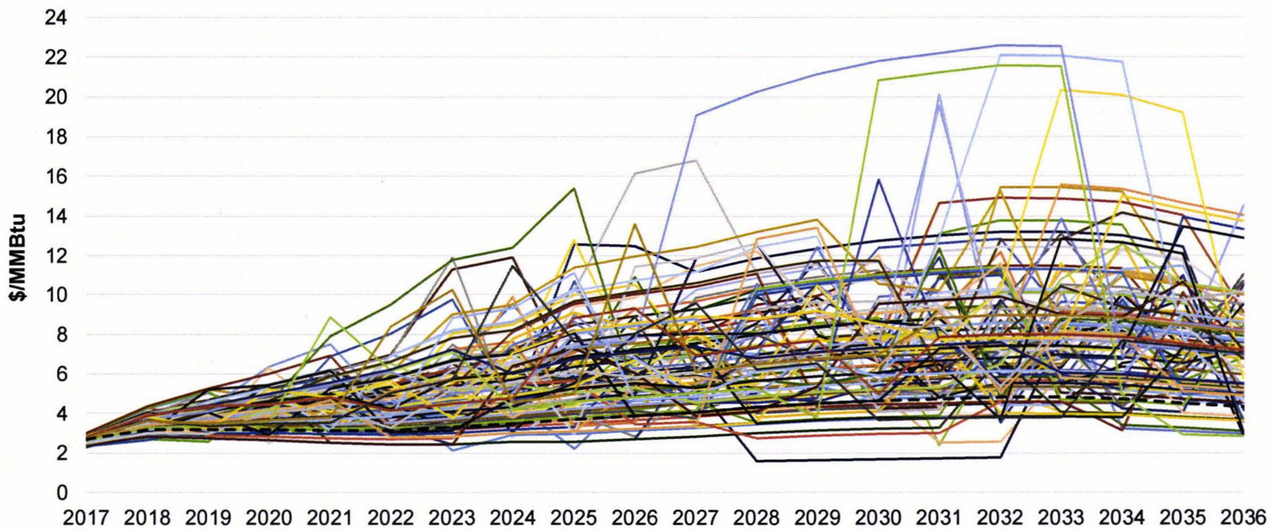


Figure 9.2 **Natural gas sampling (Nominal $/MMBtu)**

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

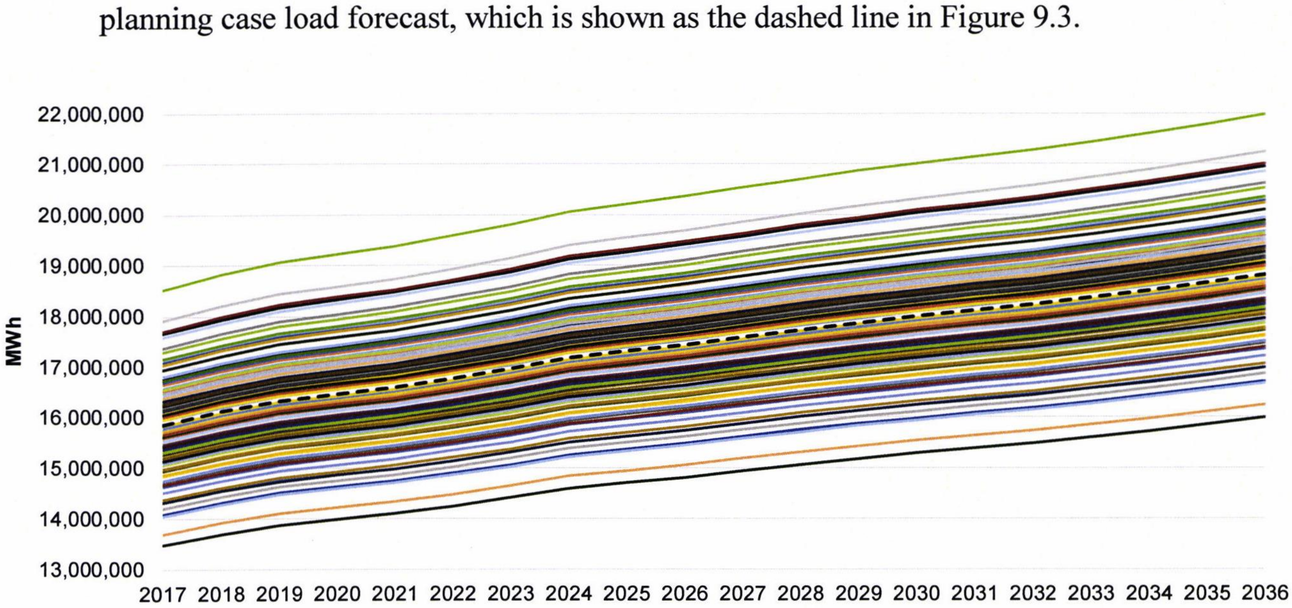


Figure 9.3 Customer load sampling (annual MWh)

3. *Hydroelectric variability*—Hydroelectric variability follows a log-normal distribution and is adjusted around the planning case hydroelectric generation forecast, which is shown as the black dashed line in Figure 9.4. The correlation factor used for the year-to-year variability is 0.50, which is based on historic values from 1975 through 2015.

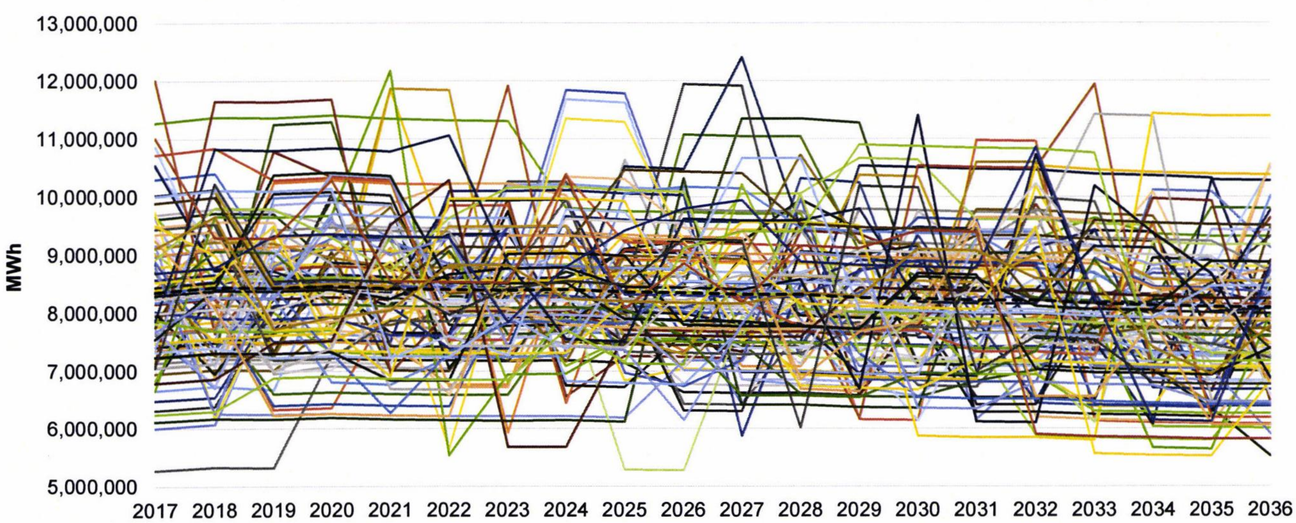


Figure 9.4 Hydro generation sampling (annual MWh)

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

The purpose of the analysis is to understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations) and how the ranges for portfolios differ.

Idaho Power created a set of 100 iterations based on the three stochastic variables (hydro condition, load, and natural gas price). Idaho Power then calculated the 20-year NPV portfolio cost for each of the 100 iterations for all 12 portfolios. The distribution of 20-year NPV portfolio costs for all 12 portfolios is shown in Figure 9.5.

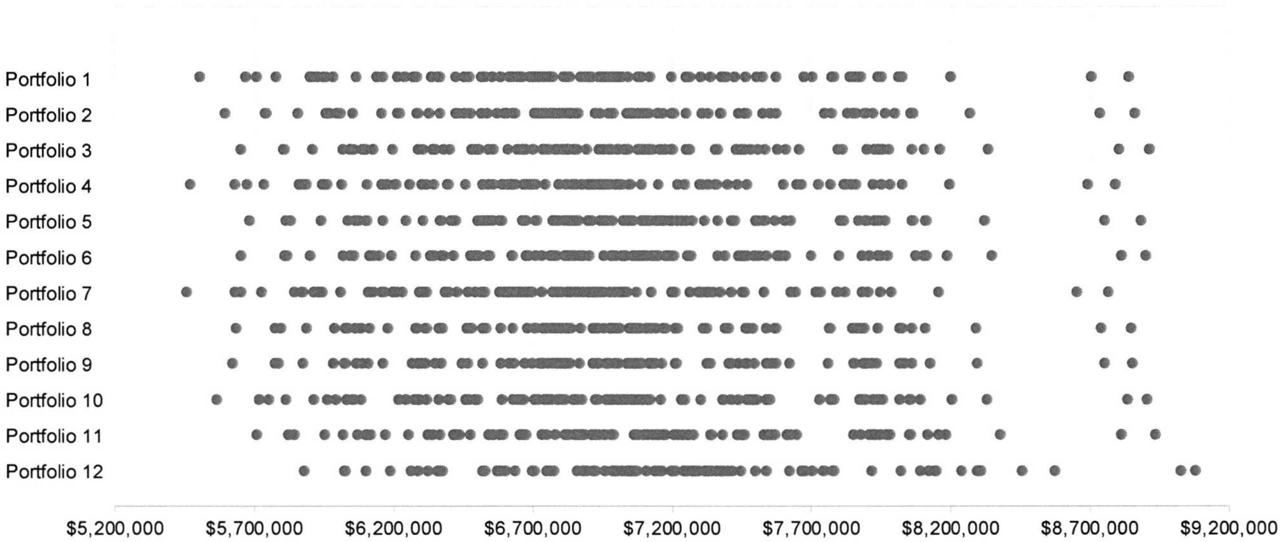


Figure 9.5 Portfolio stochastic analysis, total portfolio cost (2017, NPV, $ millions)

The horizontal axis on Figure 9.5 represents the portfolio cost (NPV) in millions of dollars, and the 12 portfolios are represented by their designation on the vertical axis. Each portfolio has 100 dots for the 100 different stochastic iterations scattered across different NPV ranges. P7 is the lowest-cost portfolio for 92 of the 100 stochastic iterations. P4 is the lowest-cost portfolio for the remaining eight stochastic iterations.

Table 9.6 is a descriptive statistical table for all 12 portfolios after the NPV is calculated for each of the 100 stochastic iterations. When calculated for the 100 iterations, P7 ranked the lowest in average, median, lowest minimum value, and lowest maximum value. P5 ranked the lowest in the standard deviation value. While P5, with 520 MW of installed solar PV capacity, has the lowest standard deviation, the approximately $20 million difference between its standard deviation and that for P7 is small when compared to the $175 million by which average portfolio costs for P7 are lower than those for P5. The difference in median portfolio costs between P7 and P5 is even greater at approximately $195 million.

Table 9.6 AURORA variable + fixed costs (NPV nominal dollars)

Portfolio	Average	Rank	Median	Rank	Standard Deviation	Rank	Minimum	Rank	Maximum	Rank
P1	$6,918,595	3	$6,894,944	3	$658,486	10	$5,505,259	3	$8,839,719	3
P2	$6,975,320	4	$6,956,065	4	$648,415	7	$5,597,752	5	$8,862,931	6
P3	$7,036,514	8	$7,005,725	8	$648,272	6	$5,651,871	8	$8,913,532	10
P4	$6,888,487	2	$6,854,217	2	$661,474	11	$5,469,530	2	$8,794,886	2
P5	$7,041,812	10	$7,026,159	10	$634,864	1	$5,686,144	10	$8,882,295	7
P6	$7,040,185	9	$7,021,875	9	$649,384	8	$5,654,847	9	$8,903,320	8
P7	$6,867,722	1	$6,831,522	1	$655,351	9	$5,458,222	1	$8,766,645	1
P8	$7,003,716	7	$6,980,730	7	$639,107	2	$5,638,058	7	$8,850,010	4
P9	$7,000,725	6	$6,970,350	5	$643,279	3	$5,623,483	6	$8,852,332	5
P10	$6,991,750	5	$6,971,770	6	$671,318	12	$5,566,108	4	$8,907,014	9
P11	$7,073,118	11	$7,071,434	11	$644,490	4	$5,708,125	11	$8,934,737	11
P12	$7,249,564	12	$7,244,615	12	$647,536	5	$5,880,258	12	$9,078,774	12

Portfolio Analysis Results in Factorial Design Format

As discussed in Chapter 8, the portfolio analysis for the 2017 IRP uses a factorial design. Table 9.7 presents the results of the design.

Table 9.7 2017 IRP portfolios, NPV, 2017–2036 ($ x 1,000)

	Primary Portfolio Element(s)				
Treatment of Jim Bridger Units 1 and 2	B2H	Solar PV/ Natural Gas	Natural Gas	Average	Rank
Invest in SCR	$6,400,696	$6,497,505	$6,530,856	$6,476,352	3
Retire Unit 1 in 2028 and Unit 2 in 2024	$6,338,683	$6,566,567	$6,508,242	$6,471,164	2
Retire Unit 1 in 2032 and Unit 2 in 2028	$6,335,771	$6,503,524	$6,483,000	$6,440,765	1
Retire Unit 1 in 2022 and Unit 2 in 2021	$6,400,507	$6,579,769	$6,671,510	$6,550,595	4
Average	$6,368,915	$6,536,842	$6,548,402		
Rank	1	2	3		

A review of the row averages indicates the lowest-cost level of the factor related to the treatment of Jim Bridger units 1 and 2 is the 2032 (Unit 1) and 2028 (Unit 2) retirement scenario. Similarly, reviewing the column averages indicates the B2H-based portfolios are low cost. These findings support P7 as the low-cost portfolio, but they are also instrumental in allowing the IRP's portfolio analysis to inform the action plan with respect to the cost-effectiveness of the SCR investments and B2H.

Solar Tipping-Point Analysis

At the direction of the IRPAC, a solar tipping-point analysis was performed to evaluate the sensitivity of the portfolio rankings to a reduction in solar cost. The solar tipping-point analysis reduces the capital cost of the solar PV included in P2, P5, P8, and P11 by 50 percent and 100 percent from the base-case capital cost of $1,375 per kW. The impact of the reduced solar capital costs on the NPV ranking of portfolios is shown in Table 9.8.

Assuming solar capital costs are reduced by 50 percent, P7 and P4 remain the two lowest-cost portfolios. P11, with 765 MW of installed solar capacity, is the third lowest in the 50-percent reduction case, moving up eight positions from its ranking under base-case capital costs. Assuming solar capital costs are reduced by 100 percent (i.e., free solar), P11, P5 (520 MW installed solar), and P2 (450 MW installed solar) are the lowest-ranked portfolios. P7 is the fourth lowest-cost portfolio in the 100-percent reduction case.

The conclusion is the economic performance of P7 under a reduction in solar costs is very robust.

Table 9.8 2017 IRP portfolios, NPV, 2017–2036 ($ x 1,000)

Portfolio Details				Planning Case		50% Reduction		100% Reduction	
Portfolio Index	Portfolio Description	B2H	Bridger Capacity Retirement	Rank	Lowest Cost Relative Difference	Rank	Lowest Cost Relative Difference	Rank	Lowest Cost Relative Difference
P1	SCR invest, B2H, recips	✓		4	$64,925	5	$64,925	7	$290,518
P2	SCR invest, DR, recips, solar			6	$161,733	6	$85,878	3	$219,766
P3	SCR invest, DR, recips, CCCT			9	$195,084	11	$195,084	11	$420,678
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	2	$2,912	2	$2,912	5	$228,505
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	10	$230,796	7	$101,391	2	$170,539
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	8	$172,470	10	$172,470	10	$398,064
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	1	–	1	–	4	$225,593
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	7	$167,753	8	$125,487	8	$299,982
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	5	$147,229	9	$147,229	9	$372,822
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	3	$64,736	4	$64,736	6	$290,329
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	11	$243,998	3	$31,413	1	–
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	12	$335,739	12	$335,739	12	$561,332

Qualitative Risk Analysis

The quantitative portfolio cost analysis indicates P7 as the lowest-cost portfolio. For the 2017 IRP, Idaho Power is assessing qualitative risk in terms of each portfolio's exposure to selected qualitative risk factors relative to P7's exposure to the same risk factors.
This comparative analysis recognizes that differing exposure to qualitative risks can lead to the selection of a preferred portfolio different from the portfolio emerging as the lowest-cost portfolio from the quantitative analysis. Idaho Power has expanded the qualitative analysis to not only assess differing exposure to qualitative risks but also differing exposure to qualitative benefits. The considered qualitative risks and benefits are described in the following sections.

Qualitative Risks

Hydro—Water Supply Risk

The long-term sustainability of the Snake River Basin streamflows is important for Idaho Power to sustain hydro generation as a resource to meet future demand. Several assumptions related to the management of streamflows were made in developing the 20-year streamflow forecasts for the IRP. These assumptions include the following:

- The implementation of aquifer management practices on the ESPA, including aquifer recharge, system conversions, and the Conservation Reserve Enhancement Program (CREP)
- Future irrigation demand and return flows
- Declines in reach gains tributary to the Snake River
- Expansion of weather-modification efforts (i.e., cloud seeding).

The assumptions used in developing the 20-year streamflow forecast are carefully planned and based on the current knowledge of Idaho Power staff in consultation with other stakeholders. Those assumptions are also subject to the limitations of the current forecasting models.

Additional risks to future hydro generation not included in the development of the 20-year streamflow outlook consist of the following:

- Changes in the timing and demand for irrigation water due to climate variability
- Changes to the sources of flow augmentation water and the potential for overestimation of flow augmentation availability in low-water years
- Long-term changes in the timing of flood control releases at Brownlee Reservoir in response to earlier snowmelt

- The potential for underestimation of the decline in reach gains within the Snake River Basin
- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

Relicensing Risk

Working within the constraints of the original FERC licenses, the HCC has historically provided operational flexibility that has benefited Idaho Power's customers. The operational flexibility of the HCC is increasingly critical to the successful integration of variable-energy resources. As a result of the FERC relicensing process, operational requirements, such as minimum reservoir elevations, minimum flows, and limitations on ramping rates, may become more stringent. The loss of operational flexibility will limit Idaho Power's ability to optimally manage the HCC, making the integration of variable-energy resources more challenging and ultimately increasing power-supply costs.

Regulatory Risk

Idaho Power is a regulated utility with an obligation to serve customer load in its service area and is therefore subject to regulatory risk. Idaho Power expects future resource additions and removals will be approved for inclusion in the rate base and it will be allowed to earn a fair rate of ROIs related to resource actions of the IRP portfolios. Idaho Power includes public involvement in the IRP process through an IRPAC and by opening the IRPAC meetings to the public. The open public process allows a public discussion of the IRP and establishes a foundation of customer understanding and support for resource additions and removals when the plan is submitted for approval. The open public process reduces the regulatory risk associated with developing a resource plan.

NOx Compliance Alternatives Risk

Six of the 12 portfolios, including P7, assume Jim Bridger units 1 and 2 will be permitted to operate beyond their regional-haze compliance dates without installation of SCRs. The remaining six portfolios either assume SCR installation or retirement of the units in 2021 (Unit 2) and 2022 (Unit 1) as stipulated by regional-haze requirements. While agreements permitting operating extensions have been reached in the past, uncertainty remains that such agreements can be reached for Jim Bridger units 1 and 2. An inability to successfully achieve permitting consistent with the assumptions of these compliance alternatives would likely have a significant effect on the costs and feasibility of portfolios with extended operations without SCR installation.

Permitting/Siting Risk

Significant challenges are often encountered during permitting and siting for energy resources. While these challenges are not uniform for all resources or for all proposed resource locations, it is nevertheless reasonable to assume all portfolios are exposed to permitting/siting risk, and no portfolio is markedly less exposed than P7; B2H planners have been collaborating with stakeholders for several years on resolving permitting/siting issues, and while challenges remain, much progress has been made.

Regional Resource Adequacy

B2H-based portfolios have higher exposure to potential regional resource inadequacies. However, Idaho Power's review of regional resource adequacy assessments conducted by the NWPCC and BPA indicates B2H will provide access to a wholesale electric market with capacity for meeting summer load needs and abundant low-cost energy. Further discussion of the NWPCC and BPA adequacy assessments is in Chapter 6.

DSM Implementation

While Idaho Power has considerable experience in DSM programs and has consistently achieved IRP energy efficiency targets, an implementation risk always exists with a new program. The actual energy savings and peak reductions may vary significantly from the estimated amounts if customer participation rates are not achieved.

Technological Obsolescence

The energy industry is experiencing considerable technological innovation, a trend expected to continue well into the future. This innovation could lead to greater market penetration for emerging resources and correspondingly drive competing resources to obsolescence. The determination of competitive resources in the energy industry of the future is highly speculative. However, current trends support the critical role the electric grid is expected to continue to play well into the future, with a growing need to move intermittently produced energy from grid locations experiencing oversupply to those experiencing undersupply. Moreover, a grid resource such as B2H positions Idaho Power to participate in the Pacific Northwest wholesale electric market as the energy sources comprising that market evolve over the coming decades. Therefore, Idaho Power qualitatively views portfolios without B2H as having greater exposure to technological innovation than those with B2H.

Qualitative Benefits

Regional Resource Diversity

The Pacific Northwest wholesale electric market is a diverse mix of renewable and thermal resources. Renewable resources primarily consist of hydropower and wind generation, with lesser amounts of solar and geothermal. B2H provides expanded access to the Pacific Northwest wholesale market and its attendant diverse mix of low-cost energy resources and abundant zero-carbon energy.

Regional Transmission Initiatives

Idaho Power has a long history of collaboration in regional transmission planning. B2H is a resource providing value to project co-participants, and also to the region as a whole, with the spread of automated energy markets, such as the western EIM. B2H positions Idaho Power and the region well in furthering the interconnectivity of the regional transmission system.

Transmission Tariff Revenue

B2H is a critical interconnection to the Pacific Northwest providing Idaho Power access to low-cost energy, capacity, and balancing. B2H, uniquely among the potential IRP resources considered, provides revenue in the form of transmission tariffs when used by other entities during periods Idaho Power is not using it to transfer energy.

Local Economic Effects

The scope of the IRP does not include an analysis of macroeconomic impacts associated with considered resource portfolios. Therefore, any evaluation of macroeconomic impacts is strictly qualitative in nature and highly conjectural. Locally sited resources, such as solar PV and natural gas-fired power plants, can be reasonably linked to localized job growth associated with plant construction and operation; however, long-term job opportunities associated with plant operation are expected to be more significant with natural gas power plants than solar PV power plants. Further, solar PV modules are substantially sourced from overseas markets, whereas fuel for natural gas power plants relies heavily on domestic production and consequently can be linked more closely to domestic macroeconomic growth. B2H can be expected to lead to construction-related job growth. Moreover, B2H, as a source for reliable and low-cost energy, is consistent with Idaho Power's mission to provide reliable and fair-priced energy services, qualities recognized as instrumental in promoting economic growth in Idaho Power's service area.

Summary of Qualitative Risks and Benefits

Table 9.9 and Table 9.10 summarize the relative risks and benefits of the 12 portfolios analyzed. As noted earlier, the qualitative risk analysis is structured as an assessment of qualitative risks and benefits in relation to the lowest-cost P7, with the objective of assessing whether qualitative risk leads to the selection of a preferred portfolio different from P7. The findings of the qualitative risk analysis do not support the selection of a portfolio other than P7 as preferred.

Table 9.9 Qualitative risk analysis

Risk	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Hydro—Water Supply Risk	=	=	=	=	=	=		=	=	=	=	=
Relicensing Risk	=	=	=	=	=	=		=	=	=	=	=
Regulatory Risk	=	=	=	=	=	=		=	=	=	=	=
NOx Compliance Alternatives Risk	<	<	<	=	=	=		=	=	<	<	<
Permitting/Siting Risk	=	=	=	=	=	=		=	=	=	=	=
Regional Resource Adequacy	=	<	<	=	<	<		<	<	=	<	<
DSM Implementation	=	=	=	=	=	=		=	=	=	=	=
Technological Obsolescence	=	>	>	=	>	>		>	>	=	>	>

< Less risk
> More risk
= Equal risk

Table 9.10 Qualitative benefit analysis

Benefit	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Regional Resource Diversity	=	<	<	=	<	<		<	<	=	<	<
Regional Transmission Initiatives	=	<	<	=	<	<		<	<	=	<	<
Transmission Tariff Revenue	=	<	<	=	<	<		<	<	=	<	<
Local Economic Effects	=	=	=	=	=	=		=	=	=	=	=

< Less benefit
= Equal benefit

CAA Section 111(d)

All 12 portfolios in the 2017 IRP comply with the mass-based carbon-emission regulations as stipulated in the final rule for Section 111(d). While Idaho Power believes carbon-emission regulations in some form are likely during the next 20 years, the final regulations will likely not be as modeled in this IRP. Qualitatively, under a non-carbon-constrained future Idaho Power believes SCR investments that extend the time period of coal-fired generation at Jim Bridger units 1 and 2 would likely result in a better financial outcome for customers. Conversely, a carbon-constrained future would favor an earlier retirement of the Jim Bridger units and preclude investment in additional SCRs at Jim Bridger. While uncertainty exists regarding carbon-emission regulations, Idaho Power is not inclined to pursue a direction toward making the SCR investments. The additional SCR investments are counter to the findings of the portfolio analysis, in which portfolios without SCRs on Jim Bridger units 1 and 2 generally performed better. Finally, the company's expressed objectives related to transitioning away from coal-fired generating capacity weigh against making additional SCR investments at Jim Bridger.

Capacity Planning Margin

Idaho Power discussed planning criteria with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by an objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2017 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P7, the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources, assuming expected-case (50^{th}-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case (50^{th}-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility or the loss of Langley Gulch. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the Northwest Power Pool (NWPP). A 330-MW reserve margin also results in a loss of-load expectation (LOLE) of roughly 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.11.

Table 9.11 Capacity planning margin

	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034	July 2035	July 2036
Load and Resource Balance																				
Peak-Hour Forecast (50th%), including DSM	(3,036)	(3,078)	(3,117)	(3,148)	(3,176)	(3,209)	(3,196)	(3,280)	(3,306)	(3,331)	(3,359)	(3,387)	(3,412)	(3,433)	(3,449)	(3,462)	(3,478)	(3,497)	(3,513)	(3,528)
Existing Resources																				
Coal																				
Boardman	54	54	54	54	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Bridger	703	703	703	703	703	703	703	703	703	703	703	703	527	527	527	527	352	352	352	352
Valmy	263	263	263	132	132	132	132	132	132	–	–	–	–	–	–	–	–	–	–	–
Coal Total	1,020	1,020	1,020	889	835	835	966	835	835	703	703	703	527	527	527	527	352	352	352	352
Gas																				
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Gas Total	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric																				
Hydroelectric (50th%)—HCC	1,067	1,070	1,071	1,071	1,071	1,069	1,068	1,067	1,065	1,063	1,061	1,059	1,057	1,055	1,053	1,051	1,049	1,047	1,045	1,043
Hydroelectric (50th%)—Other	299	300	300	300	300	299	299	299	298	298	297	296	296	295	295	294	293	293	292	291
Hydroelectric Total (50th%)	1,366	1,370	1,371	1,370	1,370	1,369	1,367	1,365	1,363	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,340	1,337	1,334
CSPP (PURPA) Total	314	314	314	319	319	319	319	319	319	318	318	318	316	314	305	303	295	295	295	295
PPAs																				
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	–	–	–	–	–	–	–	–	–
Raft River Geothermal	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Neal Hot Springs Geothermal	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Clatskanie Exchange	10	10	10	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PPAs Total	35	35	35	35	25	25	23	25	25	25	25	20	20	20	20	20	20	20	20	20

	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034	July 2035	July 2036
Transmission Capacity Available for Market Purchases	313	313	302	433	492	489	488	487	486	616	615	614	613	612	611	610	608	607	607	606
Existing Resource Subtotal	**3,765**	**3,768**	**3,759**	**3,762**	**3,757**	**3,752**	**3,879**	**3,747**	**3,743**	**3,740**	**3,736**	**3,727**	**3,545**	**3,540**	**3,527**	**3,522**	**3,333**	**3,329**	**3,327**	**3,323**
Monthly Surplus/Deficit	**729**	**690**	**641**	**614**	**580**	**544**	**683**	**467**	**437**	**408**	**377**	**340**	**134**	**108**	**78**	**60**	**(146)**	**(167)**	**(187)**	**(205)**
2017 IRP New Resources																				
2026 B2H Transmission	–	–	–	–	–	–	–	–	–	500	500	500	500	500	500	500	500	500	500	500
2033 CCCT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	300	300	300	300
2030s Reciprocating Gas Engines	–	–	–	–	–	–	–	–	–	–	–	–	–	–	36	72	72	72	126	180
New Resource Subtotal	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**500**	**500**	**500**	**500**	**500**	**536**	**572**	**872**	**872**	**926**	**980**
Remaining Monthly Surplus/Deficit	**729**	**690**	**641**	**614**	**580**	**544**	**683**	**467**	**437**	**908**	**877**	**840**	**634**	**608**	**614**	**632**	**726**	**705**	**739**	**775**
Planning Margin	24%	22%	21%	20%	18%	17%	21%	14%	13%	27%	26%	25%	19%	18%	18%	18%	21%	20%	21%	22%

Flexible Resource Needs Assessment

Idaho Power analysis for the 2017 IRP indicates Idaho Power customers and independent power producers will place increasing flexibility needs on the power system. Idaho Power analyzed historical data, then compared the historical data with a forecast of conditions in 2026. Flexibility needs increase in most months based on the analysis.

Historical Analysis

Idaho Power analyzed hourly load and hourly energy production from intermittent wind generation resources during the historical time period 2012 through 2016. Idaho Power calculated hourly net load by subtracting hourly wind generation from hourly system load (there was very limited solar production on Idaho Power's system during the 2012 through 2016 time period).

$$\textit{Hourly net load} = \textit{Hourly load} - \textit{Hourly wind generation}$$

Idaho Power then calculated the change in hourly net load over four time intervals:

$$\Delta\ \textit{Net Load}_0 = \textit{Net Load Hour}_0 - \textit{Net Load Hour}_{-1}$$

$$\Delta\ \textit{Net Load}_{-1} = \textit{Net Load Hour}_{-1} - \textit{Net Load Hour}_{-2}$$

$$\Delta\ \textit{Net Load}_{-2} = \textit{Net Load Hour}_{-2} - \textit{Net Load Hour}_{-3}$$

$$\Delta\ \textit{Net Load}_{-3} = \textit{Net Load Hour}_{-3} - \textit{Net Load Hour}_{-4}$$

Idaho Power calculated a flexibility score by averaging the four calculated absolute (ABS) changes in net load (a four-hour moving average of the hourly change in net load):

$$\textit{Flexibility Score} = [ABS(\Delta\ \textit{Net Load}_0) + ABS(\Delta\ \textit{Net Load}_{-1})$$

$$+ ABS(\Delta\ \textit{Net Load}_{-2}) + ABS(\Delta\ \textit{Net Load}_{-3})] / 4$$

The absolute change was used so a significant positive change in one hour coupled with a significant negative change in an adjoining hour would not cancel the flexibility score calculation. Significant net load changes in adjoining hours are considered to represent a genuine need for system flexibility regardless of whether the net load changes are positive or negative.

The five years of historical data yielded approximately 44,000 hourly flexibility scores.

Idaho Power then specified a flexibility threshold:

$$\textit{Flexibility Score} >= 100\ MW$$

AND

$$\textit{Flexibility Score/Hourly Net Load} >= 0.12$$

The flexibility threshold is used to identify a specific number of flexibility events. The flexibility score must be equal to or exceed 100 MW, and the flexibility score must be equal to or greater than 12 percent of the net system load to be identified as a flexibility event; both criteria must be satisfied.

The flexibility threshold and resulting number of flexibility events are not based on any specific system requirements or regulations from NERC, FERC, WECC, or any other regulatory agency. The flexibility events are solely a metric used for comparison purposes. Figure 9.6 shows the distribution of events where the flexibility score was 100 MW or greater, and Figure 9.7 shows the distribution of events where the flexibility score was 12 percent of net load or greater.

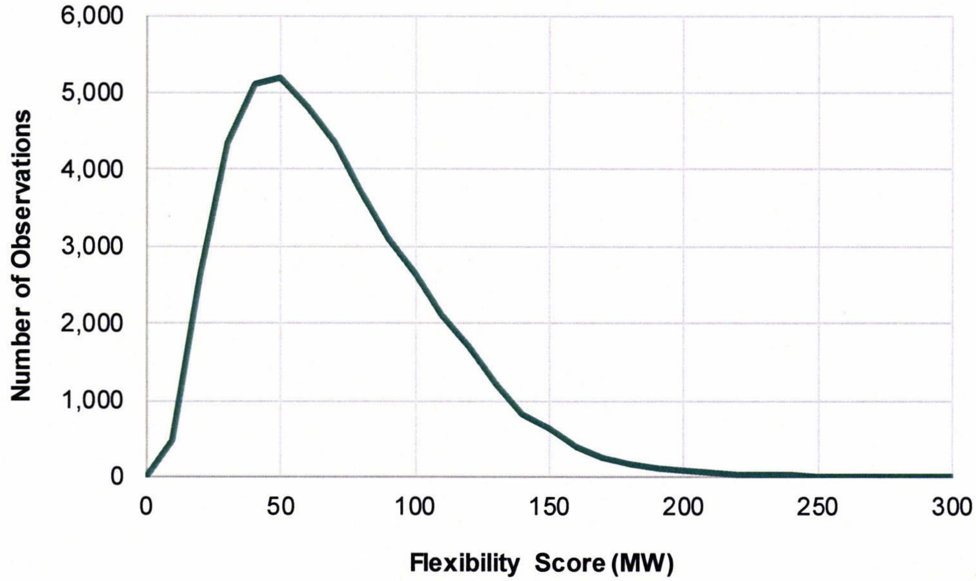


Figure 9.6 Distribution of events with flexibility score 100 MW or greater

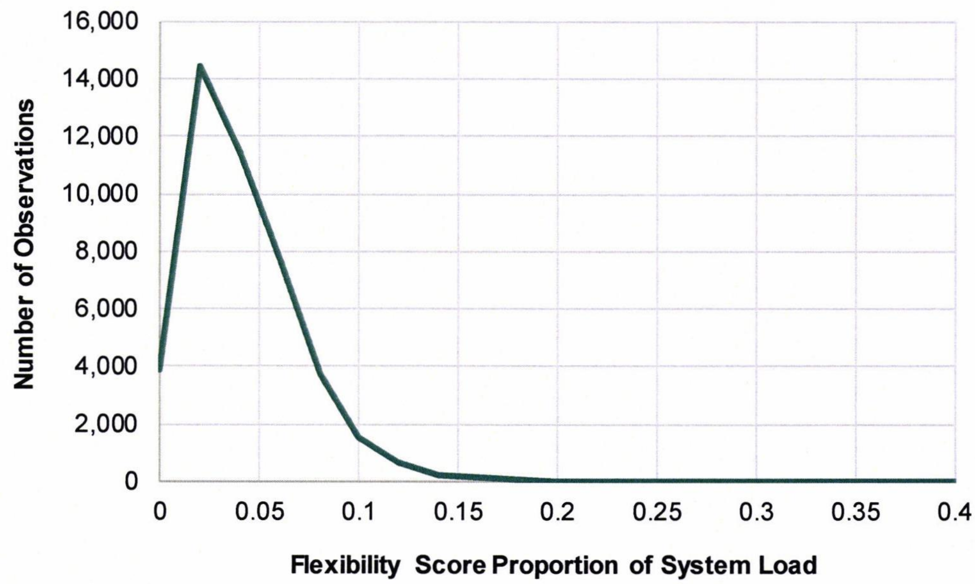


Figure 9.7 Distribution of events with flexibility score 12 percent of net load or greater

There were slightly over 600 hours during the five-year historical period that exceeded the flexibility threshold. The 600 hours represent slightly over 1.4 percent of the total hours in the historical period.

Projected Flexibility Score in 2026

Idaho Power selected 2026 as a test year in the IRP analysis. Idaho Power estimated the flexibility score for 2026 using the same arithmetic techniques that were used to analyze the 2012 through 2016 historical period. Idaho Power used forecast hourly load and forecast independent power production from intermittent renewable resources. The independent power production from intermittent resources includes both wind and solar generation facilities in 2026. As with the historical analysis, Idaho Power calculated hourly net load, the change in net load, the four-hour moving average of the change in net load, and a flexibility score based on the same flexibility threshold:

$$\textit{Flexibility Score} >= 100\ \textit{MW}$$

AND

$$\textit{Flexibility Score/Hourly Net Load} >= 0.12$$

There are 220 hours projected in 2026 that exceed the flexibility threshold, which represent about 2.5 percent of the hours in 2026. Table 9.12 shows the hours exceeding the flexibility threshold in 2026 by month, as well as the results from analyzing the historical period.

Table 9.12 Hours exceeding flexibility threshold by month

	Yearly History, 2012–2016		2026 Forecast	
Month	**Minimum**	**Maximum**	**Flex Score**	**Flex Need***
January	1	8	9	+
February	2	15	17	+
March	7	21	33	++
April	4	17	20	+
May	6	14	27	++
June	5	11	21	++
July	3	9	13	+
August	5	14	9	
September	5	18	27	+
October	7	26	30	+
November	5	18	12	
December	3	13	2	

* Plus signs indicate a forecast change in flexibility need.

Only three months in 2026—August, November, and December—are projected to have a flexibility need approximately equivalent to the flexibility need in the historical period. Three months—March, May, and June—are projected to have a significant increase in flexibility need when compared with the historical period. The other six months—January, February, April, July, September, and October—are projected to have a moderate increase in flexibility need.

March is projected to have the largest number of flexibility events at 33 in the forecast period. Idaho Power recorded 26 flexibility events in October during the historical period. The increase in flexibility events is anticipated to be manageable by comparison with the historical period. Flexibility management will likely require curtailment of intermittent renewable generation at times to maintain system stability.

The summary conclusion is that the changes in customer load and the increase in independent power production from intermittent renewable resources will increase Idaho Power's need for system flexibility in 2026.

Solar Capacity Credit

Idaho Power updated the solar PV peak-hour capacity factors based on guidance from members of the solar work group in the 2015 IRP. The update used simulated solar generation for water years 2011 through 2013, specifically focusing the analysis on solar generation occurring during the highest 150 load hours from the three water years.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to Idaho Power's system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2015 and 2017 IRPs are reported in Table 9.13.

Table 9.13 Solar capacity credit values

PV System Description	Peak-Hour Capacity Credit
South orientation	28.4%
Southwest orientation	45.5%
Tracking	51.3%

OPUC Docket No. UM 1719 examined the determination of solar capacity credit in several recently filed IRPs. The Docket No. UM 1719 settlement agreement required Idaho Power to conduct an LOLE study, or an approximation method, to validate that Idaho Power's analysis focusing on the highest 150 load hours adequately defines Idaho Power's capacity timing need. The LOLE was to include all 8,760 hours of a test year and result in an LOLP for each hour.

Idaho Power selected 2025 for examination using an approximation method for a complete LOLE study. The evaluation used median hydro and load forecasts and the AURORA hourly preferred portfolio output as a starting point. An Excel workbook was used to simulate 500 years of random outages. The 500 years of random outages resulted in an LOLE of approximately 2.07 hours per year. The 2.07 hours per year equates to an LOLE of approximately 1 day in 10 years, a frequently used standard in determining a system as resource adequate.

The hourly LOLP of the 500 iterations for 2025 is shown in Table 9.14.

Table 9.14 Hourly LOLP of 500 iterations for 2025

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
0	0.00%	0.00%	0.00%	0.00%	0.10%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.19%**
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
5	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.19%**
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
7	0.68%	0.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.16%**
8	1.25%	2.60%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	**4.15%**
9	2.41%	3.47%	0.00%	0.19%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**6.27%**
10	1.45%	2.51%	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	**4.15%**
11	0.87%	0.00%	0.00%	0.39%	0.19%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	**1.54%**
12	0.77%	0.00%	0.00%	0.39%	0.00%	0.00%	0.39%	0.00%	0.10%	0.00%	0.00%	0.10%	**1.74%**
13	0.29%	0.00%	0.00%	0.39%	0.39%	0.19%	0.68%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.93%**
14	0.10%	0.00%	0.00%	0.10%	0.19%	0.10%	1.64%	0.00%	0.10%	0.00%	0.00%	0.00%	**2.22%**
15	0.10%	0.00%	0.00%	0.19%	0.39%	0.48%	2.80%	0.19%	0.00%	0.00%	0.00%	0.00%	**4.15%**
16	0.00%	0.00%	0.00%	0.29%	0.19%	0.96%	5.30%	0.68%	0.58%	0.00%	0.00%	0.00%	**8.00%**
17	0.10%	0.00%	0.00%	0.48%	0.19%	1.06%	5.79%	1.35%	0.77%	0.00%	0.00%	0.00%	**9.74%**
18	0.58%	0.10%	0.00%	0.29%	0.48%	2.51%	8.68%	1.16%	1.35%	0.00%	0.00%	0.10%	**15.24%**
19	2.03%	2.22%	0.00%	0.48%	0.48%	1.06%	7.52%	0.96%	0.96%	0.00%	0.00%	0.10%	**15.81%**
20	1.64%	3.18%	0.00%	0.39%	0.29%	1.54%	3.28%	0.48%	0.96%	0.00%	0.00%	0.10%	**11.86%**
21	0.87%	1.25%	0.00%	0.10%	0.19%	0.87%	2.22%	0.19%	0.77%	0.00%	0.00%	0.19%	**6.65%**
22	0.39%	1.35%	0.10%	0.19%	0.29%	0.48%	0.77%	0.19%	0.19%	0.00%	0.00%	0.00%	**3.95%**
23	0.00%	0.58%	0.00%	0.19%	0.00%	0.19%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.06%**
Total	**14%**	**18%**	**0%**	**4%**	**4%**	**10%**	**39%**	**5%**	**6%**	**–**	**–**	**1%**	**100.00%**

A large percentage of the LOLP hours occur in June and July and are coincident with the 150 highest load hours used in defining the capacity credit used in the 2015 and 2017 IRPs. However, a number of the LOLP hours occur outside the hourly periods containing the 150 highest load hours. The winter-hour LOLPs are especially interesting. December, January, and February contain 33 percent of the LOLP hours identified in the study compared to 0 percent of the hours evaluated in the 150 highest hours.

The distribution of the 150 highest load hours for 2013 to 2015 is given in the following monthly hour probability table (Table 9.15).

Table 9.15 Monthly probabilities

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
11	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
12	0.00%	0.00%	0.00%	0.00%	0.00%	0.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.67%**
13	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%	1.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**2.67%**
14	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	3.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**5.33%**
15	0.00%	0.00%	0.00%	0.00%	0.00%	4.00%	5.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**9.33%**
16	0.00%	0.00%	0.00%	0.00%	0.00%	5.33%	7.33%	0.67%	0.00%	0.00%	0.00%	0.00%	**13.33%**
17	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	8.67%	0.67%	0.00%	0.00%	0.00%	0.00%	**15.33%**
18	0.00%	0.00%	0.00%	0.00%	0.00%	5.33%	9.33%	1.33%	0.00%	0.00%	0.00%	0.00%	**16.00%**
19	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	8.67%	0.67%	0.00%	0.00%	0.00%	0.00%	**15.33%**
20	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	6.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**12.67%**
21	0.00%	0.00%	0.00%	0.00%	0.00%	2.67%	2.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**5.33%**
22	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**3.33%**
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.67%**
Total	**0%**	**0%**	**0%**	**0%**	**0%**	**41%**	**56%**	**3%**	**0%**	**0%**	**0%**	**0%**	**100.00%**

The LOLE study identifying LOLP outside of the 150 highest load hours methodology leads Idaho Power to re-evaluate the 150-hour methodology and update the solar capacity credit with the best available information. This analysis will be conducted in the interim between the 2017 and 2019 IRPs, and resulting updates to the solar capacity credit will be included in the 2019 IRP.

LOLE

The solar capacity credit LOLE study Excel workbook described in the preceding section was also used to evaluate the LOLE sufficiency of Idaho Power's future system plan. The 500 random outages resulted in an LOLE of approximately 2.07 hours per year. The 2.07 hours per year equates to an approximately 1-day-in-10-years LOLE, a standard used in determining a system as resource adequate.

10. Preferred Portfolio and Action Plan

Preferred Portfolio

The cost analysis performed for the IRP included an analysis of resource portfolio costs under planning-case conditions for natural gas price, hydroelectric production, and system load. The cost analysis also included an analysis of resource portfolio costs under a range of sensitivities for natural gas price, a key cost driver. A third element of the cost analysis was the stochastic risk analysis, in which resource portfolio costs were computed for 100 different iterations (or futures) for the studied stochastic risk variables: natural gas price, hydroelectric production, and system load. The B2H-based P7 consistently outperformed the other portfolios in the cost analysis. In addition to the B2H transmission line in 2026, P7 includes 180 MW of reciprocating engines and a 300-MW CCCT in the 2030s. P7 also assumes Jim Bridger units 1 and 2 are retired early at year-end 2032 and year-end 2028, respectively, without installing SCRs.

A qualitative risk analysis found that P7 does not carry greater exposure to qualitative risk factors relative to other resource portfolios. In fact, P7 has unique qualitative benefits in a future where the electric grid is a critical element to the successful development of automated energy markets (i.e., western EIM) and the integration of expanded intermittent renewable resources. Further, P7 is consistent with Idaho Power's expressed goals related to the measured and responsible transition away from coal-fired generating capacity. Following the retirement of Jim Bridger units 1 and 2, Idaho Power's coal-fired generating capacity will have dropped to approximately one-third of the capacity on-line in 2017. Based on the analysis for the 2017 IRP, P7 is selected as the preferred portfolio. A listing of the resource additions included in P7 is provided in Table 10.1.

Table 10.1 P7 Resources

Date	Resource	Installed Capacity
2026	B2H	500 MW transfer capacity, Apr–Sep 200 MW transfer capacity, Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	CCCT (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

Action Plan (2017–2021)

The expressed objective of the portfolio design for the 2017 IRP was to inform the action plan regarding SCR investments at Jim Bridger units 1 and 2 and the B2H transmission line. Idaho Power characterized these two key resource actions as pivotal to this IRP, recognizing that an essential function of the 2017 IRP is to inform the direction of these resource decisions. With respect to B2H, the action plan includes not only actions to continue permitting and planning, but also necessary preliminary construction and construction activities extending beyond 2021. These activities are described in Chapter 6.

The IRP portfolio analysis indicates a pivot away from making the SCR investments on Jim Bridger units 1 and 2. Therefore, the action plan includes actions consistent with the planning and negotiations necessary to facilitate the units' continued operation without SCRs and their ultimate 2028 and 2032 retirement. A baseline assumption common to all portfolios is the retirement of North Valmy units 1 and 2 at year-end 2019 and year-end 2025, respectively. Actions necessary to achieve these North Valmy retirement dates and assess the import dependability from northern Nevada are included in the action plan.

The Gateway West transmission line continues to be identified as a beneficial future upgrade to Idaho Power and the region, creating additional capacity and promoting continued grid reliability in a time of expanding variable energy resources. Therefore, in support of Idaho Power's agreement with our project partner, PacifiCorp, the action plan includes actions related to the continued permitting and planning associated with the Gateway West project.

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups, such as the Northwest Energy Efficiency Alliance (NEEA)

- Continued preparation for participation in the western EIM beginning in April 2018

- Continued involvement as a stakeholder in CAA Section 111(d) proceedings or alternative regulations constraining carbon emissions

- Investigation of solar PV contribution to peak and LOLP for use in the 2019 IRP

Table 10.2 provides actions with dates for the action plan period.

Table 10.2 Action plan (2017–2021)[19]

Year	Resource	Action	Action Number
2017–2018	EIM	Continue planning for western EIM participation beginning in April 2018.	1
2017–2018	Loss-of-load and solar contribution to peak	Investigate solar PV contribution to peak and loss-of-load probability analysis.	2
2017–2019	North Valmy Unit 1	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.	3
2017–2021	Jim Bridger units 1 and 2	Plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.	4
2017–2020	B2H	Conduct ongoing permitting, planning studies, and regulatory filings.	5
2018–2026[20]	B2H	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	6
2017–2021	Boardman	Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.	7
2017–2021	Gateway West	Conduct ongoing permitting, planning studies, and regulatory filings.	8
2017–2021	Energy efficiency	Continue the pursuit of cost-effective energy efficiency.	9
2017–2021	Carbon emission regulations	Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.	10
2017–2021	North Valmy Unit 2	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.	11

Idaho Power and the Utility of the Future

A new energy world, driven by technological innovation and changing customer preferences, is emerging, one that is efficient, green, resilient, and interconnected. In the new energy world, conventional generation and increasingly complex grid connectivity will continue to exist and remain indispensable for ensuring a reliable, round-the-clock supply of power. Idaho Power is focused on transforming unidirectional powerlines into smart energy networks that incorporate renewables, providing customers with options while increasing system reliability and resiliency.

The company is investing in next-generation communication and monitoring capabilities that will facilitate the more complex web of power flow that the future will bring. Idaho Power is

[19] The B2H short-term action plan is 2017 to 2026. All other action plan items are for 2017 to 2021.

[20] B2H in-service date of 2024 or later, subject to coordination of activities with project co-participants.

laying the groundwork for future tools that will allow more automated power routing, self-healing capabilities, and enhanced power quality. The company is incorporating big-data tools and predictive analytics to anticipate issues, power flow, and usage patterns, etc., to facilitate proactive management of issues before they occur. Technological developments and capabilities will continue to occur at a rapid pace, and Idaho Power is actively, but judicially, evaluating the costs and benefits of these opportunities to take advantage of them when appropriate.

Conclusion

Hemingway Substation

The 2017 IRP indicates favorable economics associated with the B2H transmission line, the early retirement of Valmy units 1 and 2, and the early retirement (and corresponding avoided SCR investments) for Jim Bridger units 1 and 2. B2H has been treated as an uncommitted resource in every IRP beginning with the 2006 IRP. The 2017 IRP continues to show B2H as a top-performing resource alternative, capable of providing low-cost energy and capacity, as well as increasingly critical flexibility. Moreover, B2H positions Idaho Power and the region well in a future in which automated energy markets and enabling grid resources are likely to become increasingly important.

Idaho Power has expressed the objective to transition away from reliance on coal-fired generating capacity, provided this transition can be conducted in a responsible, economically beneficial, and measured manner. The findings of the 2017 IRP are consistent with this objective. The Boardman coal plant is scheduled for a 2020 retirement. A baseline assumption for the IRP is the retirement of North Valmy units 1 and 2 in 2019 and 2025, respectively. The preferred portfolio assumes the retirement of Jim Bridger Unit 2 in 2028 and Jim Bridger Unit 1 in 2032. While the North Valmy and Jim Bridger retirement dates are planning targets and subject to planning considerations with plant co-owners and/or negotiations with regulatory agencies, it can generally be asserted that over the next 15 years Idaho Power will retire more than 730 MW of coal-fired generating capacity.

Idaho Power focused the portfolio analysis for the 2017 IRP on the pivotal decisions related to SCR investments in Jim Bridger units 1 and 2 and the B2H transmission line and proffered a portfolio analysis designed to isolate these factors. However, the company recognizes resources achieving only modest market penetration to date, including notably electrochemical energy storage, are likely to achieve greater market penetration in the coming years and may outcompete the low-cost natural gas-fired resources of today. Idaho Power recognizes the importance of understanding the cost and value characteristics of all emerging resources to effective long-term resource planning.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2017 IRP. The IRPAC discussed many technical aspects of the 2017 resource plan, along with a significant number of political and societal topics at the meetings. Idaho Power's resource plan is better because of the contributions from IRPAC members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2019. The electric energy industry is experiencing what many consider a transformational era, and undoubtedly new challenges and questions necessarily addressed in integrated resource planning will be encountered in the 2019 IRP. Idaho Power will monitor the trends in the electric energy industry and adjust as necessary in the 2019 IRP.

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