2013

Integrated Resource Plan

June 2013

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ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan 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 2013 Integrated Resource Plan. 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 Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan 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 www.idahopower.com.

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1. SUMMARY

Introduction

The *2013 Integrated Resource Plan* (IRP) is Idaho Power's 11th 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). The Idaho Power resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within the Idaho Power 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 2013 IRP assumes that during the 20-year planning period—2013 through 2032—Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of the retail electricity customers in the company's Idaho and Oregon service areas and that Idaho Power will continue to operate as a vertically integrated electric utility.

The number of customers in the Idaho Power service area is expected to increase from approximately 500,000 in 2012 to nearly 670,000 by the end of the planning period in 2032. Population growth in the Idaho Power service area will require the company to add physical resources to meet the energy demands of the growing customer base.

Hydroelectric generation is the foundation of Idaho Power's energy production. Idaho Power has an obligation to serve customer loads regardless of the water conditions. Public input and regulatory support encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP, and Idaho Power continues to develop the resource plans using more conservative streamflow projections and planning criteria than median water planning but less stringent than critical water planning. Further discussion of the Idaho Power planning criteria can be found in Chapter 5.

Demand-side management (DSM) is another key resource used by Idaho Power to meet customer load. Idaho Power's main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from the demand response programs as determined through the IRP planning process. Idaho Power also strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve Idaho Power retail customers. Transmission projects are often regional resources and regional transmission 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 the 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[1] and Idaho Power retail customers.[2] The total transfer capacity of proposed transmission projects may be larger than the capacity identified in the Idaho Power IRP to accommodate the other ownership partners, third-party requests, and network customer obligations for transmission capacity.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Some earlier Idaho Power resource plans used a 10-year planning horizon. With the need for resources with long permitting and construction lead times, the requirement for a 20-year resource plan supporting independent power production contracts under the *Public Utility Regulatory Policies Act of 1978* (PURPA), and with support from the IRP Advisory Council, Idaho Power extended the planning horizon to 20 years.

The IRPs address Idaho Power long-term resource needs. Idaho Power plans for near term energy and capacity needs in accordance with the *Energy Risk Management Policy and 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 Standards* specifies an 18-month period, and Idaho Power assesses the resulting operations plan monthly.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council. The IRP Advisory Council generally meets monthly during the development of the resource plan, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public participate even though they are not members of the IRP Advisory Council. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2013 IRP Advisory Council members can be found in *Appendix C—Technical Appendix*.

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

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

Idaho Power conducted 11 IRP Advisory Council meetings, including a resource portfolio design workshop. Idaho Power and members from the IRP Advisory Council also met in several small break-out sessions to discuss certain topics in greater detail.

The IRP Advisory Council visits the Hemingway Substation.

As part of the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and natural gas power generation. The IRP Advisory Council visited the Hemingway Substation and Langley Gulch Power Plant on the field trip.

The IRP Advisory Council actively participated throughout the resource planning process. Members of the IRP Advisory Council representing the Idaho Conservation League (ICL) and Boise State University (BSU) suggested a resource portfolio that was included and analyzed as part of the 2013 resource plan.

Idaho Power believes working with members of the IRP Advisory Council and the public improves the Idaho Power IRP. Idaho Power and the members of the IRP Advisory Council recognize that final decisions on the resource plan are made by Idaho Power. Idaho Power encourages IRP Advisory Council members and members of the public to submit comments expressing their views regarding the 2013 IRP and the resource planning process in general.

Following the filing of the final resource plan, Idaho Power presents the resource plan at public meetings in various cities around the company service area. In addition, Idaho Power staff present the plan and discuss the planning process with various civic groups and at educational seminars as requested.

IRP Methodology

Preparation of the Idaho Power 2013 IRP began with the forecast of future customer demand. Existing generation resources and transmission import capacity are combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated demand response, new DSM programs, and the expansion of existing programs to revise any energy and capacity deficits. Finally, Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits.

Idaho Power evaluates resources and resource portfolios using a financial analysis. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), necessary transmission upgrades, and anticipated environmental control and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy credits (REC).

Idaho Power is part of the larger northwest and western regional energy markets, and market prices are an important component of evaluating energy purchases and sales. Idaho Power faces transmission import constraints and, at times of peak customer load, must rely on its own generation resources regardless of the regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds Idaho Power customer demand and the transmission export capacity, and Idaho Power must curtail generation on its system.

The 49 megawatt (MW) Shoshone Falls upgrade is the only committed resource in the Idaho Power 2013 IRP. The Shoshone Falls upgrade is expected to be in operation in July 2019. Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility. Committed resources are treated the same as existing resources in the IRP analysis.

An additional transmission connection to the Pacific Northwest has been part of the Idaho Power 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 transmission line. Idaho Power revaluated the Boardman to Hemingway transmission line in the 2013 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Idaho Power analyzed the resource portfolios over the entire 20-year planning period in the 2013 IRP. Idaho Power does not intend to add any resources until 2018, and Idaho Power determined it is practical to consider the 20-year planning period in total. For the 2011 IRP, the 20-year planning period was divided into two 10-year segments due to the anticipated near-term resource acquisition of the Langley Gulch combined-cycle combustion turbine (CCCT).

Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. The National Renewable Energy Laboratory (NREL) published the *Cost and Performance Data for Power Generation Technologies* in February 2012, and Idaho Power relied on the data from this publication to estimate the supply-side resource costs for the 2013 IRP.[3] Idaho Power used cost data from the company's Langley Gulch Power Plant to estimate the costs for natural gas CCCT.

The 2013 IRP forecasts load growth in the Idaho Power service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2013 IRP has identified periods of future capacity deficiencies. New resource costs are 30-year levelized estimates (based on expected annual generation) that include capital, fuel, non-fuel O&M, and the planning-case carbon adder. Figure 1.1 shows the 2013 capacity costs in dollars per kilowatt (kW) for various new supply-side resources considered in the 2013 IRP.

[3] National Renewable Energy Laboratory, *Cost and Performance Data for Power Generation Technologies*, February 2012, available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

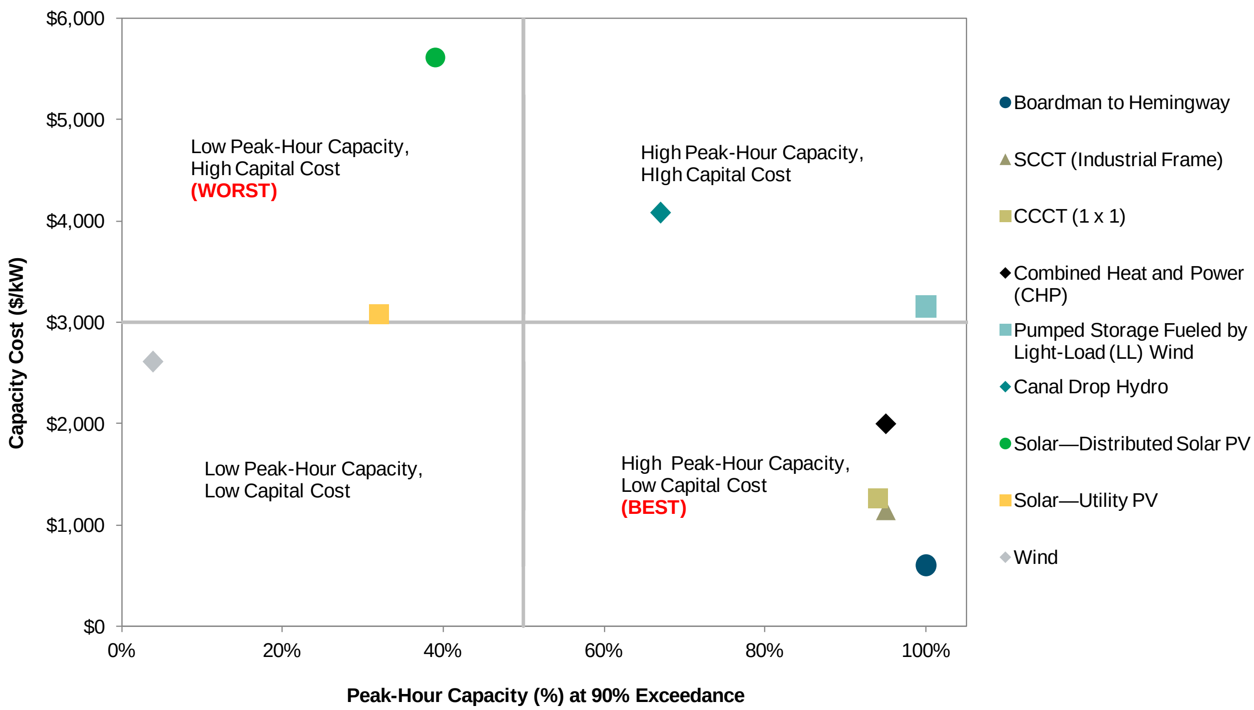

Figure 1.1 Capacity cost of new supply-side resources

Figure 1.1 shows the Boardman to Hemingway transmission line is the least-cost resource analyzed and provides the greatest level of peak-hour capacity. Simple-cycle combustion turbines (SCCT) and CCCTs are the second and third resources, respectively, in terms of capacity cost and provide slightly less peak-hour capacity than the Boardman to Hemingway line.

While it is important to evaluate the costs presented in Figure 1.1, the costs represent only part of the total resource cost (TRC). In preparing the IRP, Idaho Power also considers the value each resource provides in conjunction with the existing resources in the company’s generation portfolio. A more complete analysis is presented in the Resource Alternatives Analysis section in Chapter 7. Supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 1.2 shows the 2013 cost of energy in dollars per megawatt-hour (MWh) for various new supply-side resources considered in the 2013 IRP. Figure 1.2 allows for resource alternatives to be compared based on the capacity cost and cost of production.

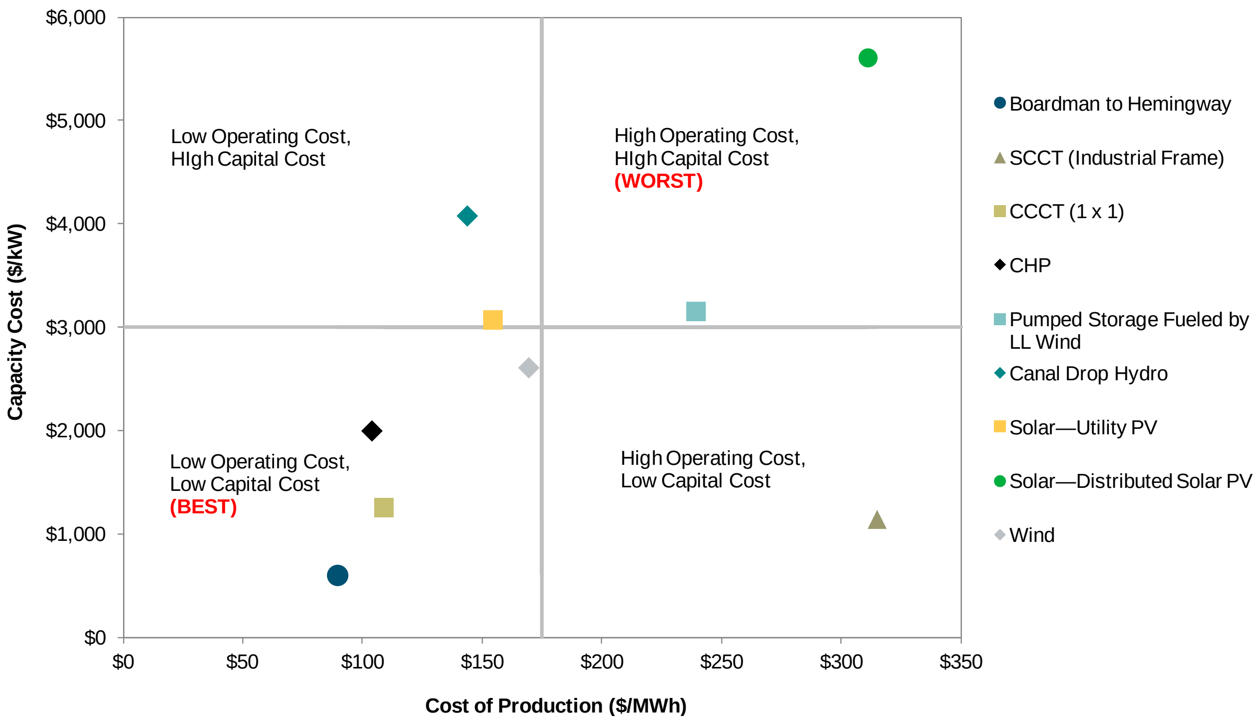

Figure 1.2 Energy cost of new supply-side resources

Figure 1.2 shows that the Boardman to Hemingway transmission line has the lowest capacity cost and the lowest cost of production. Natural gas-fueled resources are the next resources in terms of low capacity cost. CCCTs have a lower cost of energy production than SCCTs. Figures 1.1 and 1.2 show that a SCCT, with a relatively low cost of capacity, is a good resource to meet capacity deficiencies. Conversely, a SCCT is less efficient at meeting long periods of energy deficiencies. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2013 IRP is presented in Chapter 5.

Greenhouse Gas Emissions

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. 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 total CO_2 emissions (tons) and CO_2 emissions intensity (pounds per MWh). In 2010, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 37th lowest emitter of CO_2 per MWh produced and the 35th lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, Entergy, Exelon, Bank of America, Tenaska, and by grants from the Energy Foundation and the Surdna Foundation using publicly reported 2010 generation and emissions data. Figures 1.3 and 1.4 show Idaho Power's relative position to other utilities in terms of CO_2 emissions intensity and the overall quantity of CO_2 emissions. According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 58th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

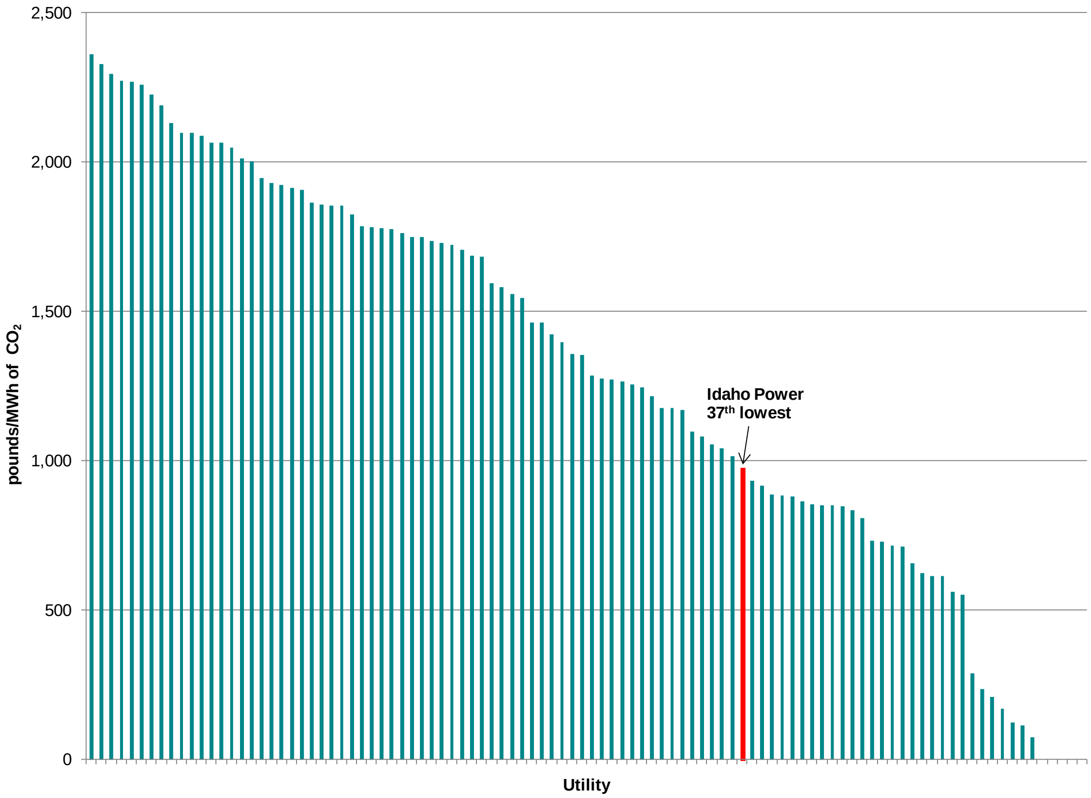

Figure 1.3 CO_2 emissions intensity of the largest 100 utilities

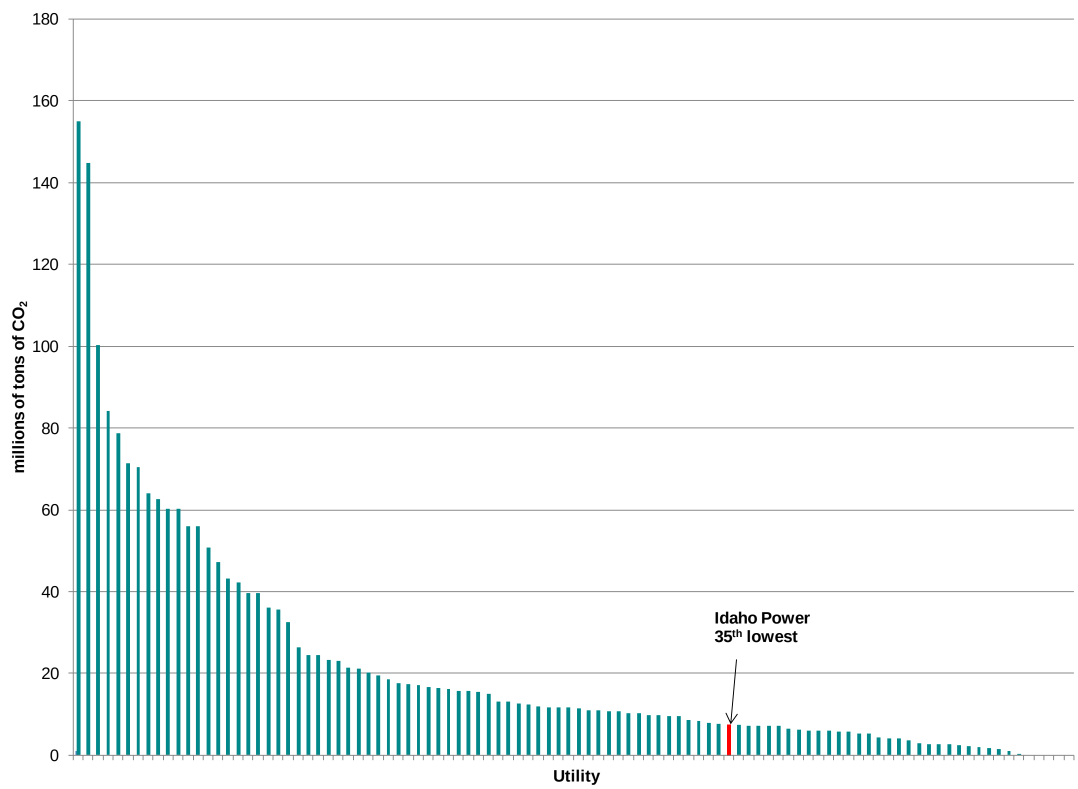

Figure 1.4 CO_2 emissions of the largest 100 utilities

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.

Currently, generation and emissions from company-owned resources are included in the CO_2 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:

http://www.idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm.

Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at www.cdproject.net. In November 2012, the Board of Directors approved the extension of the company's 2010 to 2013 goal for reducing CO_2 emission intensity. The goal is to achieve CO_2 emission intensity 10 to 15 percent below the 2005 CO_2 emission intensity from 2010 to 2015.

The 2013 IRP quantifies the cost and longer term effects of carbon regulations by including a carbon adder applied to all resources that emit CO_2. Additional details regarding the assumptions and analysis are presented in Chapter 5 and Chapter 9.

Idaho Power included a more complete discussion of climate change and the regulation of greenhouse gas emissions on pages 65 through 67 of the IDACORP, Inc., 2012 Annual Report. This climate change section is also included in *Appendix C—Technical Appendix*.

Preferred Resource Portfolio

The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was first mentioned in the 2000 IRP, and the upgrade was specifically identified in the 2006 Idaho Power resource plan. Idaho Power continues the efforts to acquire the necessary regulatory approvals and permits to begin construction. The construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018.

Idaho Power's demand response programs will be used throughout the planning period to meet resource needs. Idaho Power expects to use up to approximately 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission. The preferred resource portfolio assumes a demand response capacity of 50 MW is available beginning in 2024 and steps up to approximately 370 MW by 2032. The level of demand response capacity available will be based on the deficits identified through the IRP process or operational needs identified between IRP cycles.

The preferred resource portfolio includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to the installation and operation of the additional emission-control systems. The approximate financial commitment dates are identified in the action plan. The commitment dates are derived from the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (coal study) that Idaho Power filed in February 2013 as part of the 2011 IRP Update.

Idaho Power prepares an IRP every two years and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

Action Plan

Table 1.1 identifies the actions Idaho Power will take over the next 20 years to meet the projected capacity deficits. The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission line project has outperformed the other resource portfolios in the 2013 resource plan. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.

Idaho Power treated the Boardman to Hemingway transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

Table 1.1 Action plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings.
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings.
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology.
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology.
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW.
2018	Boardman to Hemingway	Transmission line complete and in service.
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 370 MW.

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2. Political, Regulatory, and Operational Issues

Idaho Energy Plan

In 2007, the Idaho Legislature's Interim Committee on Energy, Environment and Technology prepared, and the Idaho Legislature approved, a new Idaho Energy Plan for the first time in 25 years. With rapid changes in energy resources and policies, the committee recommended the legislature revisit the Idaho Energy Plan every five years to properly reflect the interests of Idaho citizens and businesses. In keeping with this recommendation, the plan was reviewed and updated by the Interim Committee and approved by the legislature in 2012. The Idaho Office of Energy Resources (IOER) and the Idaho Strategic Energy Alliance provided assistance to the Interim Committee during the update of the energy plan.

The 2012 update finds that Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy, despite the potential economic and political vulnerability caused by Idaho's reliance on energy imports. Idaho currently lacks significant commercial natural gas and oil wells and only generates about half the electricity it uses. Yet the state has abundant hydropower, wind, biomass, and other renewable energy sources.

Ongoing changes in energy generation and consumption provide an opportunity for economic growth within the state. While the Idaho Energy Plan acknowledges the risks attributed to advances in energy generation, transmission, and end-use technologies, it also recognizes the prospective benefits. With this recognition, the 2012 Idaho Energy Plan emphasizes five core objectives:

1. Ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho.

2. Maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans.

3. Protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources.

4. Promote sustainable economic growth, job creation, and rural economic development.

5. Provide the means for Idaho's energy policies and actions to adapt to changing circumstances.

Idaho Strategic Energy Alliance

In 2007, Governor C. L. "Butch" Otter established the IOER to oversee energy planning, policy, and coordination in Idaho. Under the umbrella of the IOER, the Idaho Strategic Energy Alliance was established to respond to rising energy costs and other energy challenges facing the state. The governor's philosophy is that there should be a joint effort between all stakeholders in developing options and solutions for Idaho's energy future.

The alliance promotes the development of a sound energy portfolio for Idaho that diversifies energy resources and provides stewardship of the environment. The alliance consists of a board of directors and 13 volunteer task forces working in the following areas:

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

Idaho Power representatives serve on many of the task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council—a group of cabinet members assigned responsibility by executive order to review suggestions from the board and interact directly with the governor. The council is led by the administrator of the IOER.

FERC Relicensing

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

Idaho Power filed a final license application (FLA) for the Swan Falls Hydroelectric Project (Swan Falls Project) with FERC in June 2008, and the new license for the Swan Falls Project was issued by FERC on September 8, 2012, for a 30-year term expiring September 1, 2042.

Idaho Power's remaining and most significant ongoing relicensing effort is 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 at the end of July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now 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 1978* (ESA); and other applicable federal laws.

Administrative work on relicensing the HCC is expected to continue until a new license is issued. After a new 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
3. Preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites
4. Preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
5. Studying and analyzing data
6. Preparing all necessary reports, exhibits, and filings responding to requests for additional information from FERC
7. Consulting on legal matters

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the current 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 2013 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, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues is expected to affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984.

The Snake River at the Murphy gage below Swan Falls.

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. 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 that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the state 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. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board (IWRB).

Idaho Power actively participated in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between the ESPA and Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River. The company had hoped implementation of the ESPA CAMP would improve aquifer levels and tributary spring flows to the Snake River. However, some of the Phase I recommendations, outlined in Table 2.1, have been slow to fully develop.

One major issue not fully resolved through the CAMP process was funding for proposed management practices. Several funding alternatives were discussed, but no long-term funding mechanisms have been established. While there have been two practices—recharge and weather modification—that have received adequate funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program and, through the cooperative effort, has greatly expanded the existing weather modification program as well as added additional forecasting and meteorological data support. The company has also established a long-term plan to continue the expansion of this program.

Table 2.1 Phase I measures included in the ESPA CAMP

Measure	Target (acre-feet)	Estimated to Date (acre-feet)
Groundwater to surface-water conversions	100,000	19,156
Managed aquifer recharge	100,000	115,000*
Demand reduction	–	–
Surface-water conservation	50,000	26,000
Crop mix modification	5,000	0
Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP)	40,000	33,368
Weather modification	50,000	124,000

*Average annual recharge from 2009 – 2012. Includes estimated for 2012

For the 2013 IRP, Idaho Power forecasted flows similar to those in the 2011 IRP; however, the declines in reach gains are extended through 2027. Based on modeling under the 90-percent exceedance forecast, declining flows reach the Swan Falls 3,900-cfs minimum in 2027. At that time, Idaho Power assumes the State of Idaho will provide appropriate management and water-rights administration under the Swan Falls Agreement to prevent further declines in surface-water flows. Figure 2.1 provides the yearly inflow to Brownlee Reservoir as forecasted for the 2013 IRP.

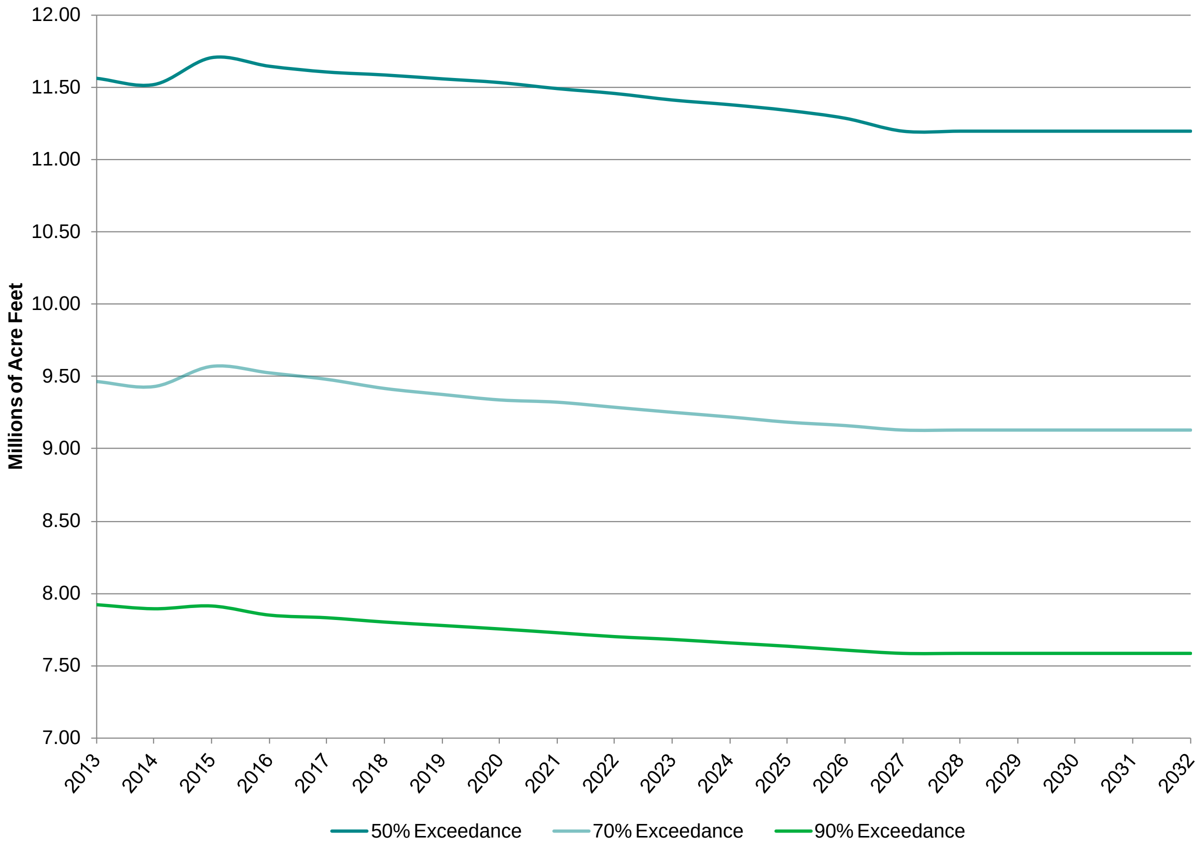

Figure 2.1 Brownlee total annual inflow—forecasted flows, 2013–2032

Wind Integration Study

Because wind generators require Idaho Power to modify the power system operations to successfully integrate wind energy, wind is a variable and uncertain generating resource. Idaho Power must adjust the generation schedule to include additional operating reserves that allow Idaho Power dispatchable generators to respond to wind variability and uncertainty.

The wind integration study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources, transmission interconnections, and customer load may be unable to provide the incremental balancing reserves to successfully integrate wind. Under low demand circumstances, the curtailment of wind generation may be necessary to balance generation with customer load. The wind integration study demonstrates that the frequency of curtailment is expected to increase when the installed wind generation capacity exceeds 800 MW. The study results indicate that wind development beyond 800 MW may lead to a considerable curtailment risk.

Idaho Power prepared the wind integration study and filed the study as part of the 2011 IRP Update. The *Wind Integration Study Report* is available at:

http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

Northwest Power Pool Energy Imbalance Market

In May 2012, the Northwest Power Pool (NWPP) initiated a study of an energy imbalance market (EIM) for the NWPP region. The 2012 study extended earlier work by WECC and various utility commissions. The NWPP study focused on issues related to hydroelectric resources in the Northwest. The NWPP analyzed the dispatch costs of the region to capture the diversity of load and wind variations that occur during the operating hour. In addition to the analysis, the NWPP study considered a mathematical simulation of the Northwest EIM. Idaho Power was 1 of over 20 entities supporting the study. The study found that an EIM would reduce the dispatch costs for the NWPP by about 3 percent when applied to the observed annual thermal dispatch cost of about $3 billion and resulted in savings between $40 and $120 million depending on the specific study assumptions. While the NWPP study found a positive benefit to cost ratio, many institutional issues remain before an EIM can be implemented in the Pacific Northwest.

For Idaho Power, there are several principle benefits to an EIM:

1. The market would provide greater access to balancing energy to accommodate intermittent generation variations within Idaho Power’s balancing area.

2. There would be a slight improvement in real-time dispatch costs.

3. The market would provide better real-time pricing for power imbalances that occur in real-time for wholesale power customers. Idaho Power supports, and will continue to participate in, the NWPP discussions; however, participation by a majority of the NWPP members will be required to realize the benefits of an EIM.

Renewable Energy Certificates

RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The RECs and the electricity produced by a certified renewable resource can either be sold together (bundled) or separately (unbundled). The purchase of a REC buys the “greenness” of that energy.

In states with REC programs, a renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hour (kWh), or 1 MWh, of electricity produced. An average residential Idaho Power customer uses about 1,025 kWh a month.

A certifying tracking system gives each REC a unique identification number to ensure the REC is used only once. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used, held, or traded.

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- Whether there is a tight supply/demand situation
- Whether the REC is used for renewable portfolio standards (RPS) compliance
- The type of power
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds from the REC sales 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. Because the RECs were sold, Idaho Power cannot claim the renewable electricity associated with those RECs was delivered to retail customers. The new REC owner has purchased the rights to claim the renewable attributes, or "greenness," of that energy.

If Idaho Power retains and retires its RECs, the company can claim electricity delivered to customers was generated by renewable resources.

Renewable Portfolio Standard

Some states have an RPS, a state policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy. In the future, there may be similar federal standards. Idaho Power anticipates that existing hydroelectric facilities will not be included in RPS calculations. However, hydroelectric upgrades on existing facilities, such as the Shoshone Falls upgrade, will likely be included in RPS calculations.

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. As a smaller utility, Idaho Power will have to meet a 10-percent RPS requirement beginning in 2025.

While the State of Idaho does not have an RPS, a federal Renewable Energy Standard (RES) is a possibility. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to position the company's resource and REC portfolio to minimize the potential effect on customers if a federal RES is implemented.

Renewable Energy Credit Management Plan

In December 2009, Idaho Power filed a REC management plan with the IPUC that detailed the company's plans to continue acquiring long-term rights to RECs in anticipation of a federal RES but to sell RECs in the near term and return their share of the proceeds to customers through the PCA mechanism. Public comments regarding the plan mirrored the positions expressed by IRP Advisory Council members, many of whom filed comments with the IPUC. In June 2010, the IPUC accepted Idaho Power's REC management plan.

Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local environmental laws and regulations. Current and pending environmental legislation relates to climate change, greenhouse gas emissions and air quality, mercury (Hg) and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species. The legislation includes the *Clean Air Act of 1970* (CAA), the *Clean Water Act of 1972* (CWA); the *Resource Conservation and Recovery Act of 1976* (RCRA); the *Toxic Substances Control Act of 1976* (TSCA); the *Comprehensive Environmental Response, Compensation and Liability Act of 1980* (CERCLA); and the ESA.

While the utility industry will continue to respond to changes in environmental legislation associated with utility operations, including emissions regulations associated with the operation of coal- and natural gas-fired generating facilities, the introduction or passage of federal energy legislation resulting in a comprehensive shift in national energy policy does not appear to be imminent. However, with atmospheric CO_2 reaching 400 parts per million (ppm), grass roots and local activities related to energy policy have increased in some parts of the country, which may lead to renewed interest in advancing comprehensive federal energy legislation.

In February 2013, Senators Bernie Sanders and Barbara Boxer introduced comprehensive legislation on climate change. The legislation has been introduced as two separate measures, cited as the following:

1. *Climate Protection Act of 2013*
2. *Sustainable Energy Act of 2013*

The package of legislation would, among other things, set a long-term emissions reduction goal of 80 percent or more by 2050; establish a carbon fee of $20 per ton of CO_2 content (or CO_2 equivalent content of methane), rising at 5.6 percent per year over a 10-year period; create a Family Clean Energy Rebate program; create a Sustainable Technologies Finance Program; and require disclosure of the chemicals used in the fracking process. Both bills are in committee.

The utility industry will continue to respond to, and be shaped by, changes in state and federal regulations, especially the changes affecting coal-fired generating facilities, the permitting of transmission facilities, PURPA regulations and implementation, and renewable energy incentives (production tax credits, cash grants, bonus depreciation, etc.). As noted previously, local activities related to climate change and energy policy may create sufficient interest to introduce climate change or comprehensive energy policy legislation that would affect the utility industry. Absent comprehensive federal energy legislation, a utility’s resource portfolios will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes.

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3. IDAHO POWER TODAY

Customer Load and Growth

An Idaho Power employee installs a Smart Meter.

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 500,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW. In July 2012, the peak-hour load reached 3,245 MW—the system peak-hour record. Idaho Power's successful demand-reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand from 2009 through 2011.

Average firm load increased from 1,200 aMW in 1990 to 1,745 aMW in 2012 (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.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,595 MW. The 960-MW increase in capacity represents enough generation to serve approximately 150,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 318-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is located in the western Treasure Valley in Payette County, Idaho. Construction of the plant began in August 2010, and the plant became commercially available in June 2012.

The data in Table 3.1 suggests each new customer adds approximately 5.5 kW to the peak-hour load and about 2.5 average kilowatts (akW) to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to the average load; industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 210,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 210,000 customers require approximately 1,150 MW of additional peak-hour capacity and about 525 aMW of energy.

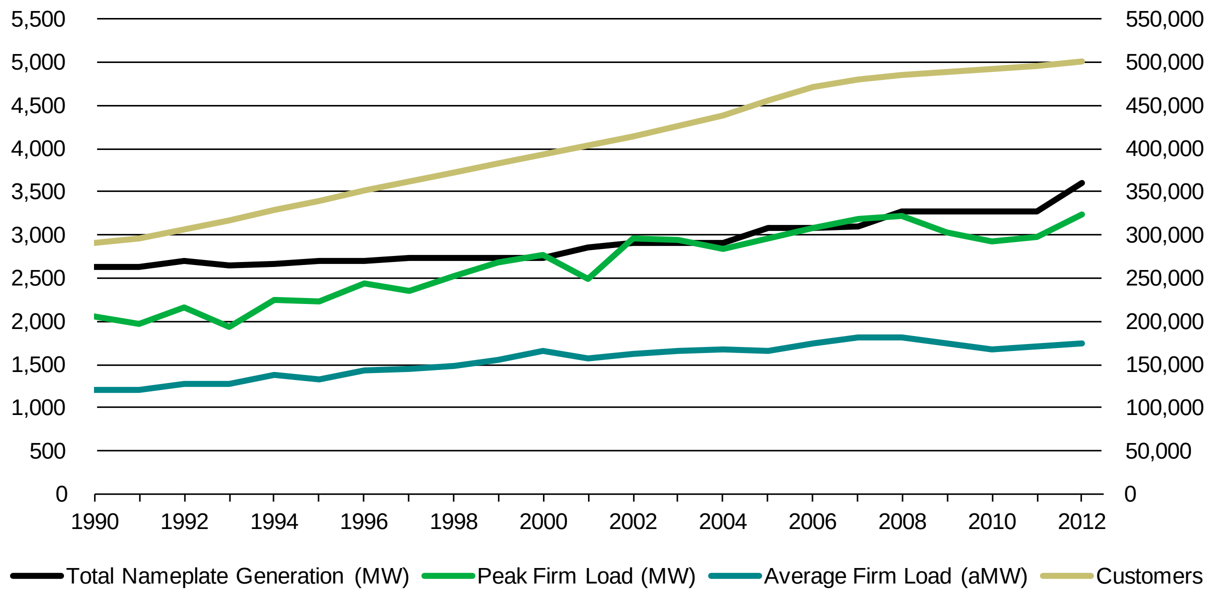

Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1990	2,635	2,052	1,205	290,492
1991	2,635	1,972	1,206	296,584
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	1,653	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,622	414,062
2003	2,912	2,944	1,657	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,660	456,104
2006	3,085	3,084	1,745	470,950
2007	3,093	3,193	1,808	480,523
2008	3,276	3,214	1,815	486,048
2009	3,276	3,031	1,742	488,813
2010	3,276	2,930	1,679	491,368
2011	3,276	2,973	1,711	495,122
2012	3,595	3,245	1,745	500,731

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

Idaho Power anticipates adding approximately 8,400 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 55 MW per year, and the average-energy requirement is forecast to grow at 21 aMW per year. More detailed customer and load forecast information is presented in Chapter 5 and in *Appendix A—Sales and Load Forecast*.

The simple peak-hour load-growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 318-MW Langley Gulch CCCT plant every six years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The plan to meet the requirements of Idaho Power's load growth is discussed in Chapter 10.

The generation costs per kW included in Chapter 5 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch Power Plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs are in 2013 US dollars and do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,400 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

2012 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and thermal generation facilities and long-term power purchase agreements (PPA) to supply the energy to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year.

In 2012, 79 percent of Idaho Power's supply of electricity came from company-owned generation resources as shown in Figure 3.2. Idaho Power purchased 11 percent of its energy from PURPA resources in 2012, and the remainder of the energy was purchased on the market or from PPAs (the four PPAs are described later in this section).

In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.3 shows Idaho Power's electricity sources for 2012, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

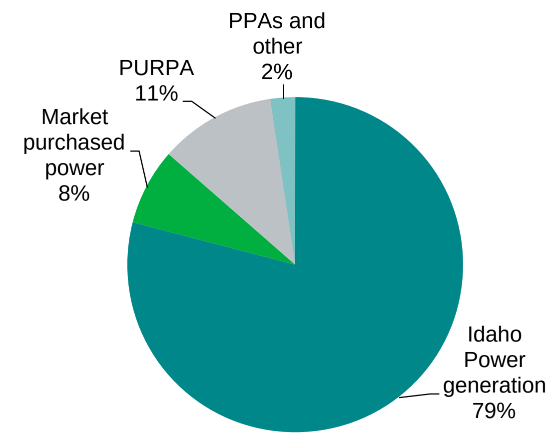

Figure 3.2 2012 energy sources by type

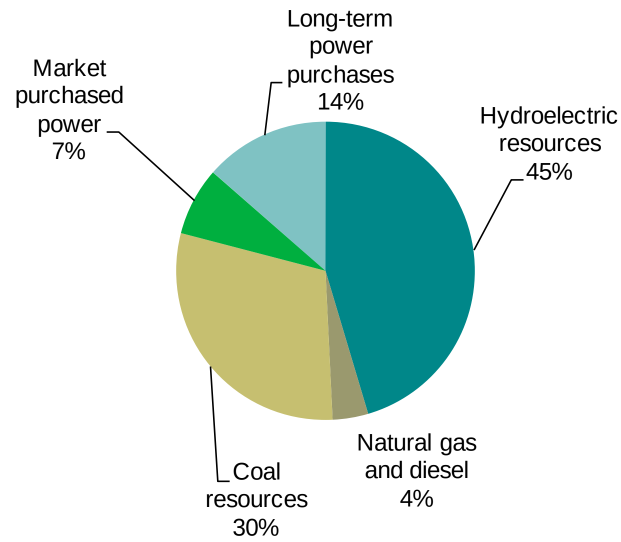

Figure 3.3 2012 energy sources

Figure 3.4 identifies the generation source by nameplate MW for Idaho Power generation in 2012. Figure 3.4 includes generation owned by Idaho Power and generation Idaho Power purchases through PPAs.

In 2012, Idaho Power purchased 2,374,795 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.5. Long-term power purchases that cannot be identified by resource type are shown as Other.

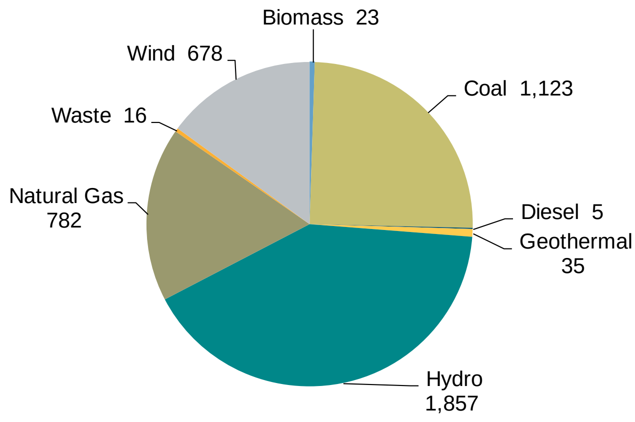

Figure 3.4 2012 Idaho Power system nameplate (MW) (owned resources plus PPAs)

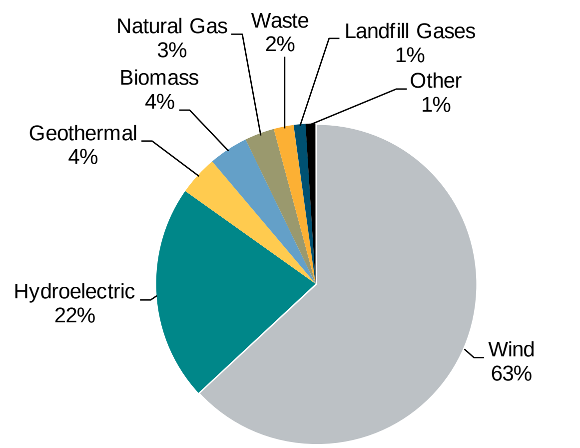

Figure 3.5 2012 long-term power purchases by resource type

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. The Idaho Power REC policy is described in Chapter 2 of this IRP.

Table 3.2 shows that the Idaho Power Green Power Program delivered 18,593 RECs to Idaho Power retail customers in 2012. The energy from the Green Power Program is reported as renewable energy delivered to Idaho Power customers.

Table 3.2 shows that no hydroelectric, wind, geothermal, or solar generation is represented as being delivered to Idaho Power retail customers in 2012 because the RECs associated with such generation were sold to other parties who purchased the right to claim that the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with the renewable generation rather than sell the RECs, the company would have been able to claim that the renewable energy had been delivered to customers. The proceeds from REC sales are returned to Idaho Power customers through the PCA as directed by the Idaho Commission in Order No. 32002 and by the Oregon Commission in Order No. 11-086.

Idaho Power generates energy at several hydroelectric projects that qualify under the State of Nevada RPS, and some of the RECs from the hydroelectric projects were sold to NV Energy in 2012. The 222,854 unsold RECs from hydroelectric projects are RECs that can only be used in Nevada, and a buyer for the RECs has not been found.

Table 3.2 2012 REC Accounting

Resource by Type	RECs Generated or Acquired	RECs Sold Off-System[1]	RECs Delivered to Idaho Power Retail Customers	Unsold RECs
Hydroelectric	276,843	(53,989)	0	222,854
Solar (Oregon Solar)	238	(173)	0	65
Wind (Elkhorn)	314,145	(314,145)	0	0
Geothermal (Neal Hot Springs)	23,690	(23,690)	0	0
Purchased renewables (Green Power Program)	18,593	0	(18,593)	0
Total	**633,509**	**(391,997)**	**(18,593)**	**222,919**

[1] When RECs are sold, Idaho Power can no longer claim the environmental attributes associated with the renewable resource. Therefore, the energy from REC sales is reclassified as Purchased Power.

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 all of 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 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

Table 3.3 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
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**	

The following sections describe Idaho Power's existing supply-side generation resources and long term PPAs.

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects located 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 approximately 30 percent of the total energy generated. 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 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 plan, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the ESA.

Brownlee Reservoir is the only 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 one 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 the primary purpose is to provide a stable power source, Brownlee Reservoir is also used for flood control, navigation, 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 (USACE) 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 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 (mid-Snake) projects, with all of 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 plan adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook plan 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. The three projects are operated within the FERC license requirements to coincide with the daily system peak demand when the 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 license the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power operated the Bliss and Lower Salmon facilities under both 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 will be 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 water is needed are especially beneficial. Acquiring water through the water bank also helps the company to improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2012 with Water District 65 in the Payette River system to rent 10,000 acre-feet of storage water released in February 2012.

In August 2009, Idaho Power also entered into a five-year (2009–2013) water-rental agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of main stem Snake River hydroelectric projects.

In 2011, the company extended the Shoshone–Bannock rental agreement for two additional years, 2014 and 2015. The company plans to schedule delivery of the water between July and October of each year during the term of the agreement. The Shoshone–Bannock agreement was executed in part to offset the effect of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Idaho Power intends to continue to pursue water-rental opportunities as part of its regular operations.

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 system above Milner Dam. Idaho Power is continuing to work with the stakeholders in the upper Snake River to expand the program.

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 the right combination of abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation.


An Idaho Power remote cloud-seeding generator.

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 the two methods provides the most flexibility to successfully place 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 nucleus that allows 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 (http://weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 5 and 28 percent annually. Idaho Power estimates cloud seeding provides an additional 124,000 acre-feet from the upper Snake River, and 224,000 acre-feet from the Payette River. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2012 to 2013 winter season, the program included 17 remote-controlled, ground-based generators and 1 aircraft for operations in the Payette Basin. The Upper Snake River Basin program included 19 remote-controlled, ground-based generators operated by Idaho Power and

25 manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

Thermal 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. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

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. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

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. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. Portland General Electric (PGE) has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative has 10 percent ownership. As the majority owner of the plant, PGE is the operator of the Boardman facility.

The 2013 IRP assumes Idaho Power's share of 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 Environmental Protection Agency (EPA) related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NO_x) emissions. At the end of 2012, the net-book value of Idaho Power's share of the Boardman facility was approximately $23.1 million. Additional emission controls are required to be installed to continue operating the Boardman plant through 2020.

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 is located south of New Plymouth in Payette County, Idaho. Construction commenced in 2010, and the plant became commercially available in June 2012. The Langley Gulch project connects to existing 230-kilovolt (kV) transmission lines to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon.

Peaking Facilities

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 located 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 photovoltaic (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.

Idaho Power 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; owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events; and has a 200-watt (W) solar water pump used for demonstrations and promoting solar PV technology.

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 June 1, 2013, there were 287 solar PV systems interconnected through the company's net metering service with a total capacity of 1.896 MW. At that time, the company had received completed applications for an additional 15 net metered solar PV systems representing an incremental capacity of 0.13 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.4.

Table 3.4 Net metering service customer count and generation capacity as of June 1, 2013

	Number of Customers			Generation Capacity (MW)		
Resource Type	**Active**	**Pending**	**Total**	**Active**	**Pending**	**Total**
Solar PV	287	15	**302**	1.896	0.130	**2.026**
Wind	71	3	**74**	0.577	0.010	**0.587**
Other/hydroelectric	10	0	**10**	0.147	0.000	**0.147**
Total	**368**	**18**	**386**	**2.620**	**0.140**	**2.760**

Oregon Solar Photovoltaic Pilot Program

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 will acquire up to 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 last enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In addition to the smaller facilities under the pilot program, Idaho Power is required to either own or purchase the generation from a 500-kW, utility-scale solar PV facility by 2020. Under the rules, if the utility scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the State of Oregon RPS.

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.

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 not exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is not currently receiving RECs from the Raft River geothermal 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.

The Neal Hot Springs Geothermal 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, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Public Utility Regulatory Policies Act

In 1978, the US congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. 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 both the IPUC rules and regulations for all PURPA facilities located in the state of Idaho and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar but not identical for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2013 IRP was completed in August 2012.

As of March 31, 2013, Idaho Power had 105 PURPA contracts with independent developers for approximately 789 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power projects. Of the 105 contracts, 103 were on-line as of March 31, 2013, with a cumulative nameplate rating of approximately 783 MW. Figure 3.6 shows the percentage of the total PURPA capacity of each resource type under contract.

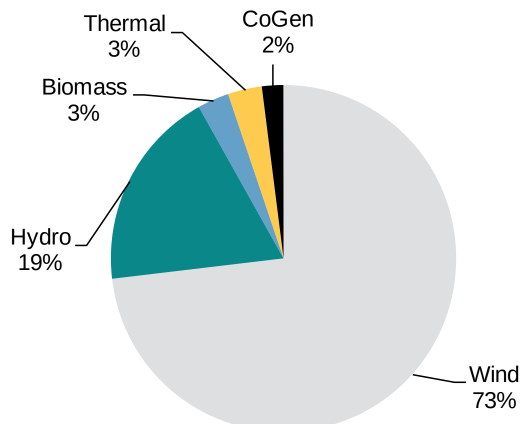

Figure 3.6 PURPA contracts by resource type

Published Avoided Cost Rates

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided cost. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost rate Idaho Power is required to include in PURPA contracts.

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04, GNR-E-11-01, and GNR-E-11-03). The main issues in the cases included the disaggregation of larger, utility-scale projects to qualify for the published avoided cost rate and the methods used to calculate the published rate.

On December 18, 2012, the IPUC issued Order No. 32697. Order No. 32697 included new rules and regulations in regard to the numerous PURPA issues presented in the various cases that began in November 2010. Some highlights are as follows:

- The published avoided cost rate is available only for wind and solar projects with a nameplate rating of less than 100 kW.
- For all other resource types, the eligibility cap will remain at 10 aMW.
- Idaho Power's proposed incremental cost IRP method was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A different published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project retains the RECs associated with the project for QF contracts containing published avoided costs.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that are negotiated agreements.

On May 6, 2013, the IPUC issued Order No. 32802 concerning the reconsideration of Case No. GNR-E-11-03. Order No. 32802 affirms many of the commission rulings in Order No. 32697. PURPA contracting continues to be an issue in Idaho, and approximately 200 MW of various QF projects currently have some form of a filed dispute in regards to PURPA contracts with Idaho Power.

In April 2012, the OPUC issued Order No. 12-146, which opened OPUC Docket UM 1610. Docket UM 1610 addresses many of the same PURPA issues identified in the recent Idaho PURPA cases as well as unique PURPA issues associated with the Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013.

Wholesale Contracts

The fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative expired in 2011. The 83-MW contract with PPL EnergyPlus, LLC expired in 2012. Idaho Power imported the energy from PPL EnergyPlus using the Jefferson line, and Idaho Power continues to explore opportunities to use transfer capacity on the Jefferson line.

Idaho Power presently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts). The Elkhorn, Raft River Geothermal, Neal Hot Springs, and Clatskanie Exchange contracts were described previously in the Power Purchase Agreements section of this IRP.

Market Purchases and Sales

Idaho Power relies on regional 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 markets during peak-load periods, and the existing transmission system is used to import the energy purchases. A reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the PCA.

Committed Supply-Side Resources

Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility and are treated like existing resources in the IRP analysis.

Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric Project (Shoshone Falls project0 from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single 50-MW unit that will result in a net upgrade of 49 MW.

In July 2010, FERC issued a license amendment for the project. The license amendment allows two years to begin construction and five years to complete the project. The company requested and received a two-year extension from FERC on May 1, 2012, that requires construction to commence by July 1, 2014. A project team was assembled in 2012 and has started project preparations, including completing a geotechnical investigation and a survey of the construction site. Currently, Idaho Power intends to request an additional two-year extension from FERC regarding the major segments of the expansion project while progressing with the replacement of the existing gated spillway, which will occur during the next two years. Construction of the main expansion project will start in 2016 and finish in 2019.

For the 2013 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in 2019. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median and other projected water conditions, some uncertainty exists regarding future Snake River streamflows that would not only effect the Shoshone Falls project, but also all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls upgrade, it is included in the 2013 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the Idaho. Prior to filing for a Certificate of Public Convenience and Necessity (CPCN) with the IPUC, Idaho Power plans to update the economic analysis of the Shoshone Falls upgrade, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

4. Demand-Side Resources

DSM programs are an essential component of Idaho Power's resource strategy, and its portfolio of programs consists of demand response and energy efficiency programs.

Interior view of the Micron Center for Professional Technical Education at the College of Western Idaho. Energy efficiency upgrades were made using incentives from Idaho Power's Building Efficiency program.

Demand response targets decreasing peak loads through either customer behavior or automations that respond during periods of extreme loads when all other resources, including market purchases, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side baseload resources. Energy efficiency, demand response, and energy efficiency education programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations and funded Northwest Energy Efficiency Alliance (NEEA) market transformation activities since 1997. Due to the indirect nature of savings from market transformation, NEEA effects are not forecasted or accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs of offering them, are published annually. The most recent analysis can be found in the *Demand-Side Management 2012 Annual Report Supplement 1: Cost Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their potential effect over the 20-year IRP planning horizon as part of the IRP process. For the 2013 IRP process, Idaho Power engaged in a comprehensive energy efficiency potential study that also analyzed potential energy-saving opportunities not currently offered as part of its portfolio of programs. The forecast of energy savings was developed from the potential study. The resulting forecast and program history were analyzed against the load forecast process to better understand the energy efficiency opportunities not accounted for in the load forecast.

Demand response was treated as a resource option during the 2013 IRP portfolio selection process. The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. Idaho Power's demand response programs have been available to meet that need. However, an analysis done for the 2013 IRP indicates no peak-hour shortages until 2016.

The anticipated lack of peak-hour capacity deficits from 2013 to 2015 is primarily due to a slower-than-expected economic recovery, causing slower customer growth than previously forecasted, as well as two previously anticipated large-load customers that did not materialize. Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program.

Cost-effectiveness analyses of DSM forecasts for the 2013 IRP are presented in more detail in the *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2012 Annual Report* contains a detailed description of Idaho Power's 2012 energy efficiency program portfolio along with historical program performance (appendices B and C are filed as part of this IRP). A complete review of the energy efficiency potential study and report can be found in the 2012 annual report filing supplement, *Demand-Side Management 2012 Annual Report Supplement 2: Evaluation*, which is available on the Idaho Power website at:

http://www.idahopower.com/EnergyEfficiency/reports.cfm

DSM Program Performance

While the IRP planning process primarily looks forward, it also important to review the past DSM investments to understand their effects on system sales and loads. Accumulated annual savings from energy efficiency investments grow over time as loads decrease based on measure lives of the more efficient equipment and measures adopted and maintained by customers each year. Additionally, past performance of demand response programs provides a good indication of future potential for reducing peak summer loads and affecting IRP resource portfolios.

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in an annual load reduction of over 111 aMW or over 960,000 MWh of reduced supply-side energy production to customers through 2012. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 11-year period from 2002 through 2012. Over two-thirds (67%) of savings since 2002 from energy efficiency have come from programs available to commercial and industrial customers, with the other third of savings coming from residential and irrigation customer programs.

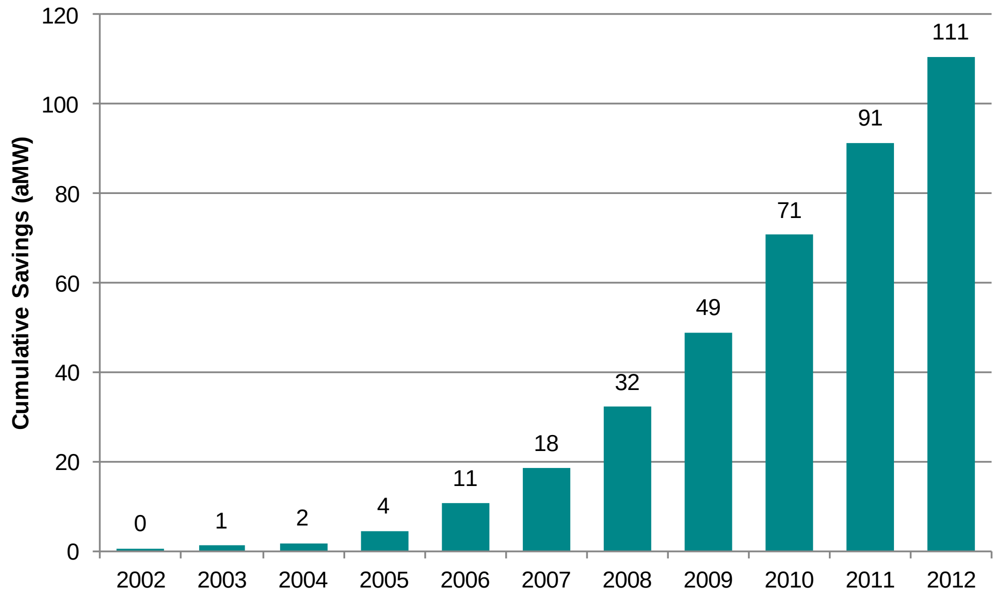

Figure 4.1 Cumulative energy efficiency savings, 2002–2012 (aMW)

Energy efficiency has proven a reliable, low-cost resource for Idaho Power, as the annual performance targets set for resource planning as part of IRPs from 2004 to 2011 have consistently been met or exceeded. Figure 4.2 shows the annual or incremental savings from energy efficiency and its associated planning targets starting with the 2004 IRP, when DSM programs were first fully implemented in the IRP process.

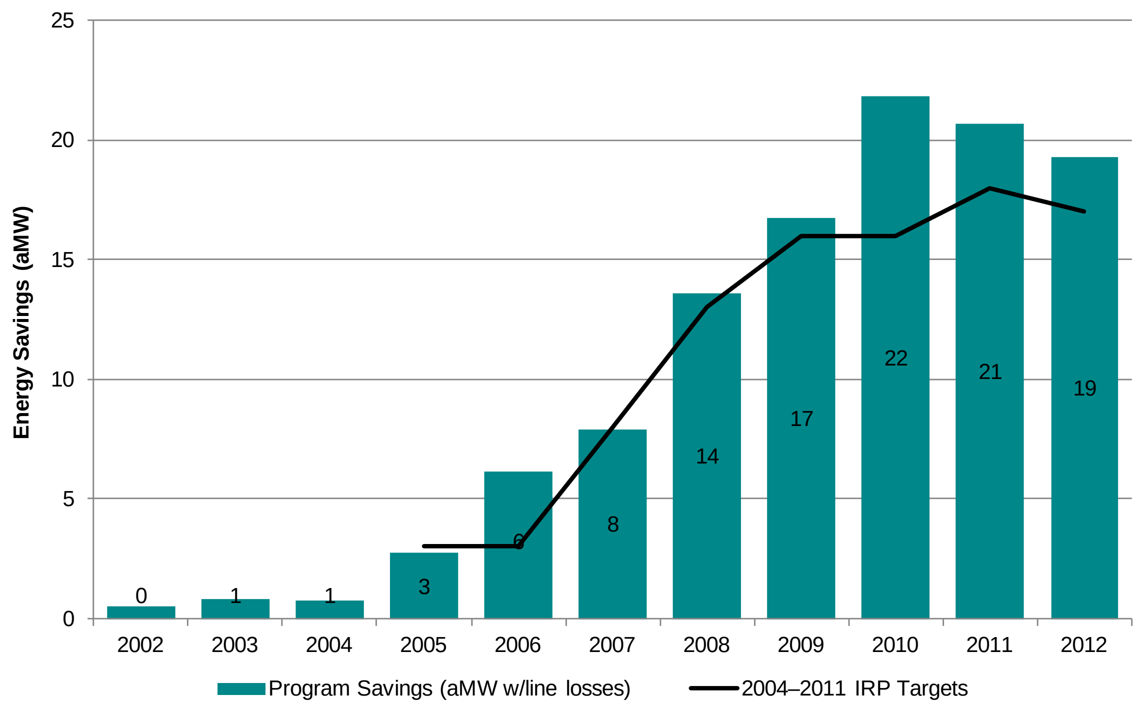

Figure 4.2 Annual energy efficiency savings and IRP targets, 2002–2012 (aMW)

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP and have provided a low-cost capacity resource. Three distinct programs, each targeting different customer classes, have made up the demand response portfolio:

- *A/C Cool Credit*—The A/C Cool Credit program cycles residential air conditioners on and off. A/C Cool Credit has provided 11 percent of the demand response portfolio, or an average of 37 MW, since 2009.

- *Irrigation Peak Rewards*—Irrigation Peak Rewards is a direct load-control program allowing irrigation pumps to be turned off during called events. Irrigation Peak Rewards contributes the largest load reduction, with 76 percent of demand response capacity, or an average of 268 MW.

- *FlexPeak Management*—Commercial and industrial customers can participate in the FlexPeak Management program, where customers commit to reduce demand at their facilities during called events. The FlexPeak Management program has averaged 45 MW of program capacity, or 12 percent of demand response reduction potential, since 2009.

Figure 4.3 shows the annual demand response program capacity between 2004 and 2012. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards program to a dispatch program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity from the Irrigation Peak Rewards program, respectively, which was not used based on the lack of need and the cost to dispatch.

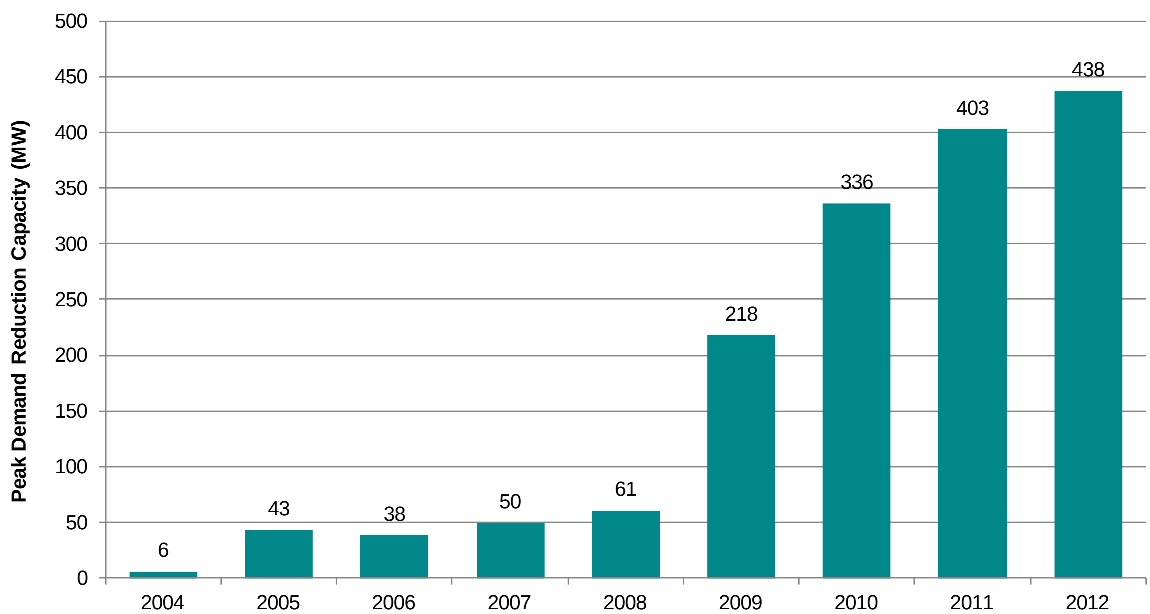

Figure 4.3 Demand response peak reduction capacity, 2004–2012 (MW)

Demand response programs have been a low-cost and reliable capacity resource for helping meet extreme summer peak loads. Programs have traditionally cost between $35 and $50/kW over a 20-year horizon to build, maintain, and manage—less than the cost of other peak capacity resources available for meeting capacity deficits. Figure 4.4 shows the annual program reduction capacity along with the committed demand reductions for the 2004 to 2011 IRPs.

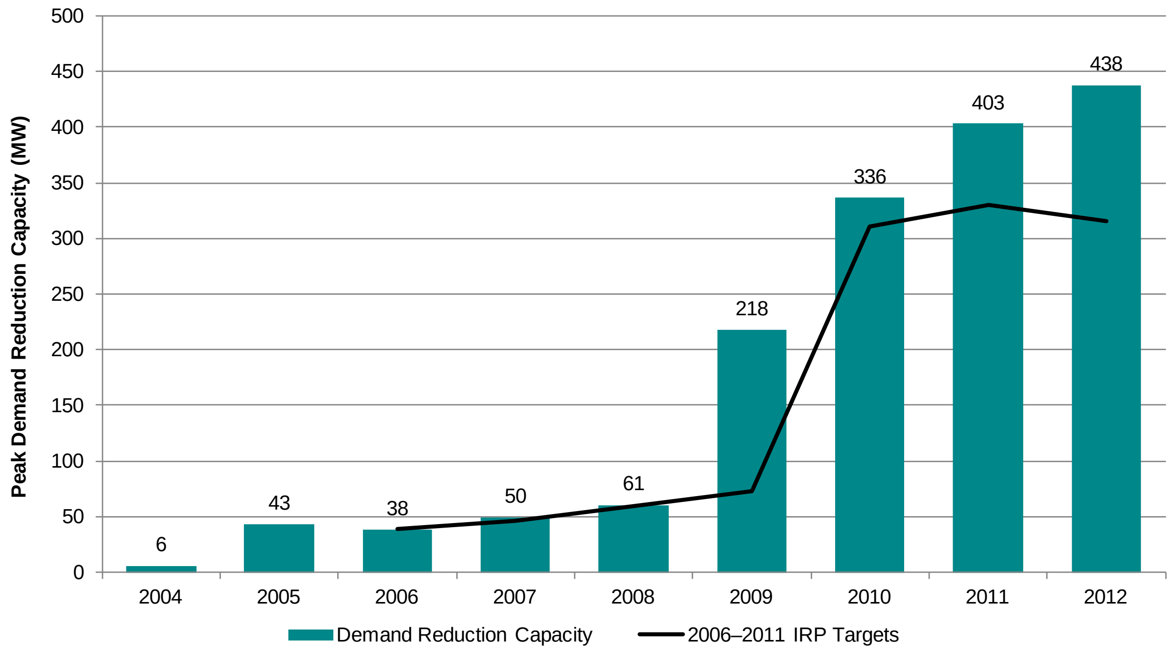

Figure 4.4 Demand response peak reduction capacity with IRP targets, 2004–2012 (MW)

New Energy Efficiency Resources

For the 2013 IRP, EnerNOC, Inc., was retained to develop a 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the potential study were as follows:

- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 21 years (2012–2032) within the Idaho Power service area.
- Assess potential energy savings associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide an executable dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Review and update load profiles by sector, program, and end use.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2012 through 2032.

Because the market characterization process bundles industries and building types into homogenous groupings, 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 individual customer's efficiency goals and prior history of participation along with projects that are known and projected to occur in the future.

There were three levels of potential considered as part of the study:

- *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 available other measure, where applicable. The retrofit measures are phased in over a number of years, which is greater for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the TRC test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential takes into account 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 potential study followed a typical approach in developing the achievable potential. First, the market was characterized by customer class. The classification phase included segmenting the market by housing type for residential and understanding the various industries and building types within the commercial and industrial customer classes. Saturations of end-use technologies within customer segments are assessed to help determine which technologies are available for efficient upgrades. The next step was screening measures and technologies for cost-effectiveness, then assessing the adoption rates of technologies to determine the forecast of achievable potential. More detailed information about cost-effectiveness methodologies and approaches can be found in *Appendix C—Technical Appendix*.

The annual savings potential forecast is measured in MWh, but to convert the savings to average annual or monthly demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are divided by either 8,760 hours (hours in a year) or a corresponding number of monthly hours subject to a load shape. All forecasts are prepared in terms of generation equivalency and therefore include line losses of 10.9 percent that account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the customer.

Table 4.1 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2013 to 2032 in five-year blocks, in terms of average demand reduction (aMW) by customer class. In 2017, the forecast reduction for 2013-to-2017 programs will be 69 aMW; by the year 2022, the reduction across all customer classes increases to 129 aMW. By the end of the IRP planning horizon in 2032, 261 aMW of reduction are forecast to come from the energy efficiency portfolio, with 60 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C—Technical Appendix*.

Table 4.1 Total energy efficiency current portfolio forecasted effects (2013–2032) (aMW)

	2017	2022	2027	2032
Industrial/Commercial	45	86	125	157
Residential	18	30	50	76
Irrigation	6	13	21	28
Total	**69**	**129**	**196**	**261**

Table 4.2 shows the cost-effectiveness summary from the potential study. The table shows the net present value (NPV) analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficiency technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing resources, the 2011 IRP preferred portfolio of generation resources, and the 2013 IRP natural gas price forecast and carbon-adder assumptions.

Table 4.2 Total energy efficiency portfolio cost-effectiveness summary

	2032 Load Reduction (aMW)	Resource Costs (20-Year NPV)	Alternate Energy Benefits (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs ($/kWh)
Industrial/Commercial	157	$188,245,928	$467,521,430	2.5	0.028
Residential	76	$123,886,346	$190,935,664	1.5	0.046
Irrigation	28	$52,623,496	$76,220,052	1.4	0.049
Total	**261**	**$364,755,770**	**$734,677,146**	**2.0**	**0.035**

The value of avoided energy over the 20-year investment in the energy efficiency measures was twice the TRC when comparing benefits and costs resulting in an overall benefit to cost ratio of 2. The levelized cost to reduce energy demand by 261 aMW is 43.5 cents per kWh from a TRC perspective. Figure 5.7 in Chapter 5 compares the energy costs of the energy efficiency programs with the other supply-side resource options.

Once the energy efficiency forecast is complete, the forecasted energy efficiency is included in the IRP planning horizon and the load and resource balance analysis. Planning assumptions in the energy efficiency potential forecast include new programs, technology, known codes and standards changes, customer adoption behavior, and cost-effectiveness that are explicitly incorporated into the potential study and reflect differences between the energy efficiency forecast and the amount of efficiency accounted for in the load forecast. A key difference between the two views of efficiency is that the load forecast accounts for energy efficiency effects based on previous years' program performance while the forecast from the potential study is more prospective in its approach. The amount of energy efficiency not captured by the load forecast is accounted for in the load and resource balance analysis.

Table 4.3 shows the new energy efficiency potential portion of the total energy efficiency forecast included in the load and resource balance. In 2017, the incremental energy efficiency savings will reduce energy loads by 38 aMW; in 2022, average loads will be reduced by 76 aMW. The full 20-year capacity of the program additions and changes is 188 aMW of average-energy reduction.

Table 4.3 New energy efficiency resources (2017–2032) (aMW)

	2017	2022	2027	2032
Industrial/Commercial	30	59	90	116
Residential	4	9	26	51
Irrigation	4	8	15	21
Total	**38**	**76**	**131**	**188**

Demand Response Resources

In fall 2012, the company's IRP analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. The most recent analysis from the 2013 IRP indicates no peak-hour shortages until mid-2016. Based on the results of this analysis, Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.

Typical irrigation pivot supplied by a pump participating in the Irrigation Peak Rewards demand response program.

In the preferred 2013 IRP portfolio, demand response is used to satisfy temporary deficits from 2016 to 2018 prior to the build out of Northwest transmission. Demand response from 2016 to 2017 would be built out to 150 MW capacity, then it would be built up to 370 MW to meet the deficits from 2024 through the end of the planning period.

Conservation Voltage Reduction

Conservation voltage reduction (CVR) regulates the feeder voltage within the lower half of the standard operation range. In acknowledging the 2011 IRP, the OPUC directed Idaho Power to assess available cost-effective CVR resource potential and propose a course of action.
The OPUC also requested Idaho Power incorporate the energy savings and reduced peak demand from the CVR program in the load and resource balance forecast.

Idaho Power considers it prudent to validate the benefit of the CVR program before expanding it beyond the initial study area. New technologies and methods of measurement are available to validate energy savings and reduced peak demand. Idaho Power intends to analyze the CVR effects at two of the six substations—the Alameda and Meridian substations—where CVR has been implemented.

Idaho Power expects to complete the CVR analysis in 2016. If the analysis confirms energy savings and reduced peak demand, Idaho Power will evaluate extending CVR measures to other Idaho Power facilities.

The actual savings from the current CVR implementation are not significant enough to be incorporated into the IRP load and resource balance forecast.

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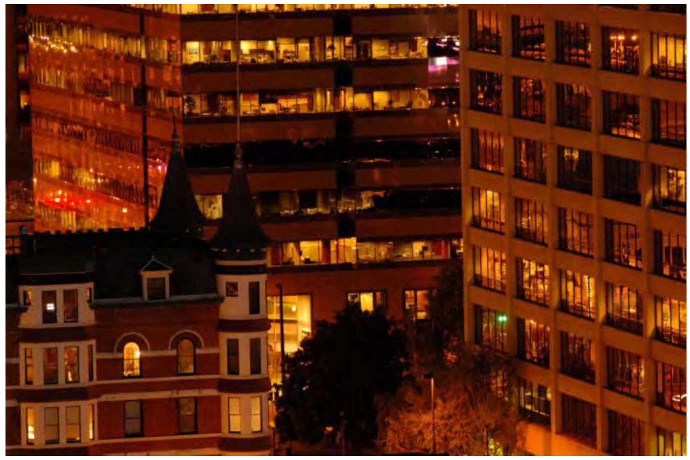
5. Planning Period Forecasts

The IRP process requires Idaho Power to prepare numerous forecasts that can be grouped into four main categories:

1. Load forecasts
2. Generation forecasts
3. Fuel price forecasts
4. Financial assumptions



Forecasting load growth is essential for Idaho Power to meet future needs of customers.

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 2013 IRP.

Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning (A/C) in the months of June, July, and August. For a number of years, the growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. However, both measures are important in planning future resources and are part of the load forecast prepared for the 2013 IRP.

The expected case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not precisely follow the path suggested by the expected case forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with abnormal weather. The 70th-percentile and 90th-percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced the 2013 IRP load forecast results. The national, state, metropolitan statistical area (MSA) and county economic 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. National economic drivers from Moody's Analytics are also used in developing the

2013 IRP load forecast. The forecasts of households, population, employment, output, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

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 are analyzed to address load variability due to weather. Idaho Power has generated load forecasts for 70th-percentile and 90th-percentile weather. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

Idaho Power's system load is highly dependent on weather. The three scenarios allow a careful examination of load variability and how the load variability may affect resource requirements. It is important to understand how the probabilities associated with the load forecasts apply to any given month. For example, an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

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

Economic Effects

The national recession that began in 2008 affected the local economy and energy use in the Idaho Power service area. The severity of the recession resulted in a significant decline in new customers. Idaho Power added less than 2,500 new residential customers in 2011. Recently, the number of new residential customers added each year has increased to approximately 4,000.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by 0.9 percent in 2010 and a slight decline in 2011. The 2009 through 2011 time period was the first time overall energy use had declined since the energy crisis of 2001. In 2012, system electricity sales increased by 1.8 percent over 2011. The 2012 sales increase was due to economic recovery in the service area and higher irrigation sales.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period, and the 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 due to the 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 number of households in Idaho is projected to grow at an annual average rate of 1.1 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service-area household projections are derived from applying Idaho Power's share to county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with an expected declining consumption per household, results in a 1.1-percent average residential load-growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.5 percent annually from 416,000 at the end of 2012 to nearly 555,000 by the end of the planning period in 2032.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*. For example, the expected annual average system load growth of 1.1 percent (over the period 2013 through 2032) is comprised of a residential load growth of 1.1 percent, a commercial load growth of 1.1 percent, an irrigation load growth of 0 percent, an industrial load growth of 1.7 percent, and an additional firm load growth of 1.2 percent.

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery in the economic forecast used in the 2011 IRP was too optimistic, particularly in the near term. The updated economic forecast variables used as drivers in the 2013 IRP forecast reflect a lower near-term recovery relative to the 2011 IRP economic forecast drivers but are nonetheless conveying sustained and increased economic recovery. The stalled recovery in the national- and service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series. Longer term, the effect of economic recovery is tempered in the forecast by higher retail electricity price assumptions that incorporate estimates of assumed carbon legislation, which decreases the average load forecast. The decrease is especially evident in the second 10 years of the forecast period.

Additional significant factors that put downward pressure on load growth relative to the 2011 IRP forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected.

For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from the sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, 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 current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest 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, 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. 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 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

Peak-Hour Load Forecast

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 95th-percentile forecast as the basis for peak-hour planning in the IRP. The 95th-percentile forecast is based on the 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,245 MW—was recorded on July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on June 30, 2008, at 3:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011, the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also had a significant effect on reducing peak demand. The 2013 IRP load forecast projects peak-hour load to grow by approximately 55 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance as a supply-side resource.

Figure 5.1 and Table 5.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th-percentile, and 95th-percentile weather effects on the expected (median) peak forecast. The 95th-percentile forecast uses the 95th-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.

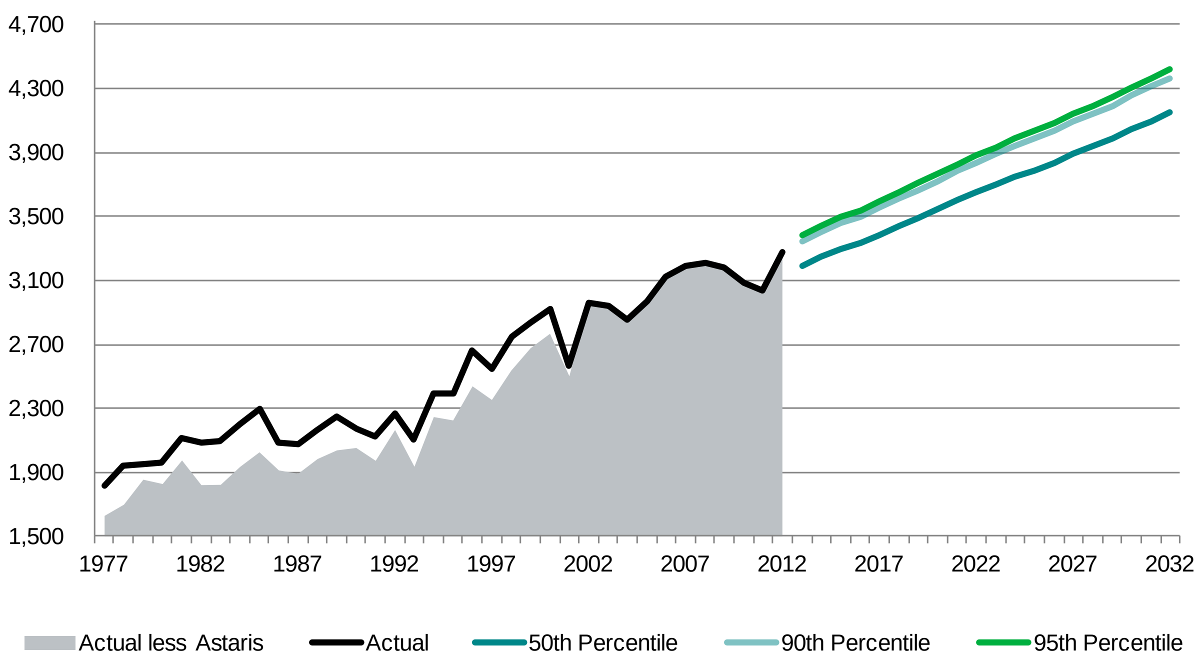


Figure 5.1 Peak-hour load-growth forecast (MW)

Table 5.1 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2012 (Actual)	3,245	3,245	3,245
2013	3,189	3,344	3,382
2014	3,245	3,403	3,442
2015	3,294	3,456	3,495
2016	3,335	3,500	3,541
2017	3,387	3,555	3,596
2018	3,437	3,609	3,651
2019	3,489	3,664	3,707
2020	3,544	3,722	3,766
2021	3,601	3,782	3,827
2022	3,651	3,835	3,881
2023	3,701	3,889	3,935
2024	3,748	3,939	3,987
2025	3,790	3,985	4,033
2026	3,836	4,034	4,083
2027	3,888	4,090	4,139
2028	3,936	4,141	4,191
2029	3,984	4,192	4,244
2030	4,045	4,256	4,308
2031	4,097	4,312	4,365
2032	4,147	4,365	4,418
Growth rate (2013–2032)	**1.4%**	**1.4%**	**1.4%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,189 MW in 2013 to 4,147 MW in 2032—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 3,382 MW in 2013 to 4,418 MW in 2032. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime 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.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by two load forecasts that reflect load uncertainty resulting from differing weather-related assumptions. Figure 5.2 and Table 5.2 show the results of the two forecasts used in the 2013 IRP reported as annual system load growth over the planning period. There is approximately a 50-percent probability Idaho Power's load growth will exceed the expected-case forecast and a 30-percent probability of load growth exceeding the 70th-percentile forecast. The projected 20-year average annual compound growth rate in the expected load forecast is 1.1 percent.

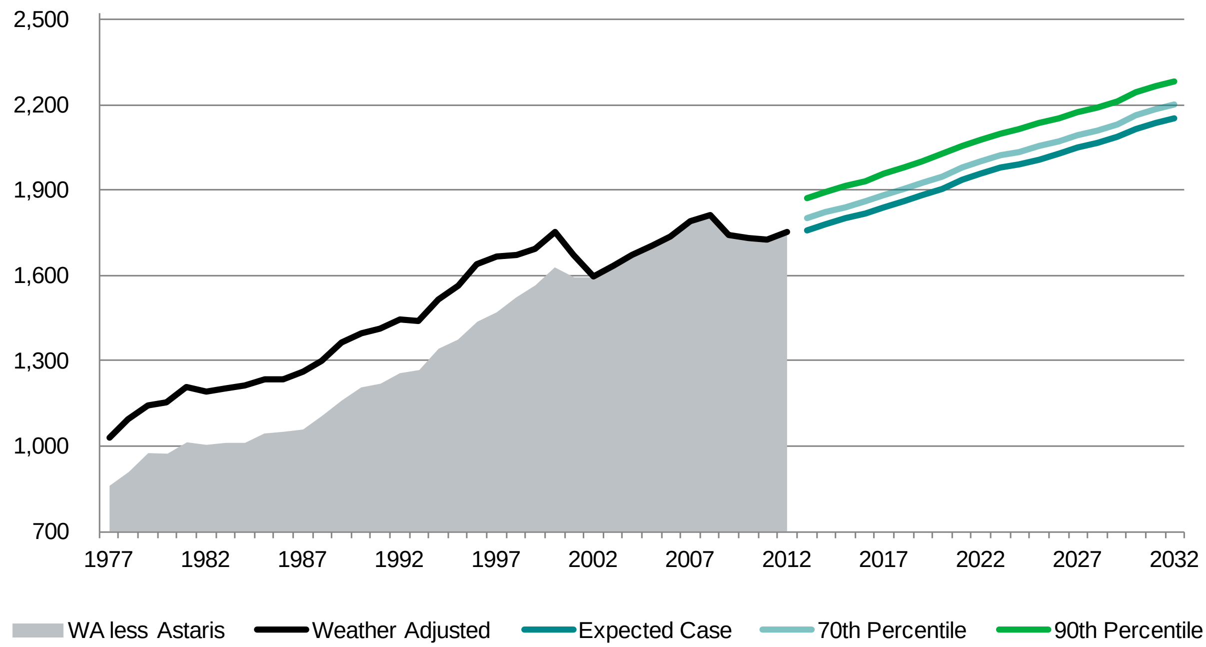


Figure 5.2 Average monthly load-growth forecast (aMW)

Table 5.2 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2013	1,759	1,800	1,872
2014	1,782	1,823	1,895
2015	1,800	1,841	1,914
2016	1,818	1,859	1,933
2017	1,842	1,884	1,959
2018	1,862	1,904	1,980
2019	1,883	1,926	2,002
2020	1,906	1,949	2,026
2021	1,934	1,977	2,055
2022	1,956	2,000	2,078
2023	1,977	2,021	2,100
2024	1,992	2,036	2,116
2025	2,009	2,054	2,134
2026	2,028	2,073	2,153
2027	2,049	2,094	2,176
2028	2,065	2,110	2,192
2029	2,087	2,132	2,214
2030	2,116	2,162	2,244
2031	2,137	2,183	2,265
2032	2,154	2,201	2,284
Growth rate (2013–2032)	**1.1%**	**1.1%**	**1.1%**

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, 70^{th}-percentile water to forecast hydroelectric generation, and 95^{th}-percentile average peak-day temperature to forecast monthly peak-hour load.

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), and Hoku Materials. The special-contract customers are described briefly as follows.

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 (Q/A), systems integration, and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on 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 in 2013 and 2014, then stay flat throughout the remainder of the planning period.

Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated have not been included in this sales and load forecast.

“Special” Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as “Special” included with the additional firm-load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared in August 2010, several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power’s service area. It was determined at that time there was a real possibility of the new large load materializing. However, no customer signed a contract. The IPUC and OPUC directed Idaho Power not to include new large-load customers in the forecast until a contract is signed. Idaho Power has assumed this “Special” contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are not included in the 2013 IRP sales and load forecast.

Existing 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 all of 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 describe recent events or changes accounted for in the load and resource balance regarding Idaho Power’s hydroelectric, thermal, and transmission resources.

Brownlee Dam is part of the HCC.

Hydroelectric Resources

For the 2013 IRP, Idaho Power continues the practice of using 70th-percentile 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 50^{th}-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 50^{th}-, 70^{th}-, and 90^{th}-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2013 IRP is included in *Appendix C—Technical Appendix*.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70^{th}-percentile year in 2010 is identical to a 70^{th}-percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the Eastern Snake River Plain Aquifer (ESPA) is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA Comprehensive Aquifer Management Plan (CAMP) includes demand reduction and weather-modification measures that will add new water to the basin water budget. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years are expected to continue and result in a return to declining basin outflows assumed to persist well into the 2020s. The declining basin outflows for this IRP are assumed to continue through 2027, when Swan Falls flows of the 90^{th}-percentile forecast drop to the irrigation season minimum of 3,900 cfs. Idaho Power assumes the decline of flows to the Swan Falls minimum would cause the State of Idaho to take remedial action to prevent further decline. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on trends in Snake River Basin hydrologic conditions as a standard part of forecasting hydroelectric generation for future IRPs.

The Snake River canyon above Swan Falls.

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. During 2013—a year with markedly worse-than-median water conditions—flow augmentation water from the Upper Snake River and Boise River basins was delivered during May.

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 2013 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 5.3 shows historical April-to-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 equilibrate beyond 2027.

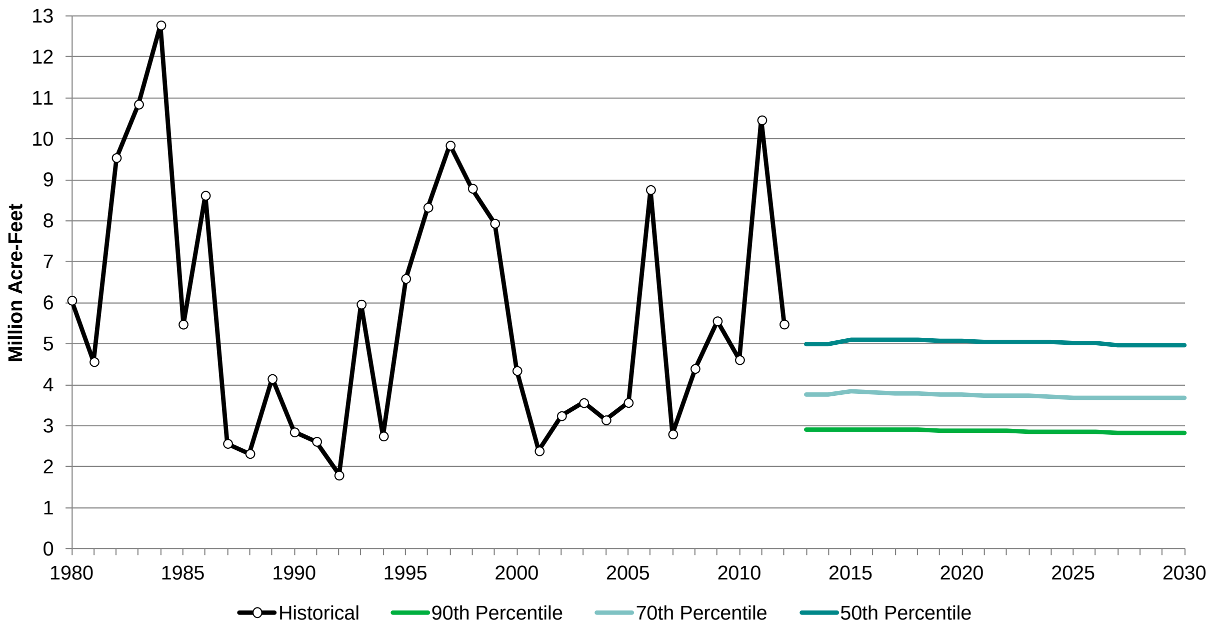


Figure 5.3 Brownlee historical and forecast inflows

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes there is too much uncertainty 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 2013 IRP. A discussion of climate change, including expectations of possible effects on the Snake River water supply, is included in the *Appendix C—Technical Appendix*.

Coal Resources

Idaho Power's coal-fired generating facilities have typically operated as baseload resources. Monthly average-energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the 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*.

Plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Boardman plant in 2014 and 2018, the North Valmy plant in 2015, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The EPA signed the proposed requirements and deadlines for the installation of pollution-control equipment for compliance with RH BART at the Jim Bridger plant on May 23, 2013. The EPA is planning to sign a notice of final rulemaking for RH BART for the Jim Bridger plant on November 21, 2013. The total generation loss for the air-quality modifications at all three plants is less than 1 percent.

The 2013 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The assumed date is the result of an agreement reached between the ODEQ and PGE related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. The EPA formally approved the agreement, and the agreement was published in the Federal Register on July 5, 2011.

Idaho Power prepared the coal study as part of the 2011 IRP Update. The report was filed with the IPUC and OPUC in February 2013.

Planned Upgrades at Jim Bridger

In addition to the selective catalytic reduction (SCR) emission-control upgrade mentioned previously, turbine upgrades are continuing at the Jim Bridger plant, and the replacement of the high-pressure/intermediate-pressure and low-pressure turbines on Unit 2 were completed in spring 2013. Upgrades of the high-pressure/intermediate-pressure and low-pressure turbines on Units 3 and 4 and upgrades to the low-pressure turbines on the remaining units are currently being evaluated.

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 high-load occurrences in summer and winter months. 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 230 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 165 aMW with an on-demand peaking capacity of 318 MW in the 2013 IRP.

Load and Resource Balance

Idaho Power has adopted the practice of assuming 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 a sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares the load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. The updated load and resource balance showing the Idaho Power existing and committed resources for average-energy and peak-hour load is shown in *Appendix C—Technical Appendix*.

Average Monthly Energy Planning

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 a reserved network capacity. Figure 5.4 shows the monthly average-energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 5.4 also include the forecast effect of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade when it is available. Figure 5.4 illustrates there are no energy deficits through the planning period.

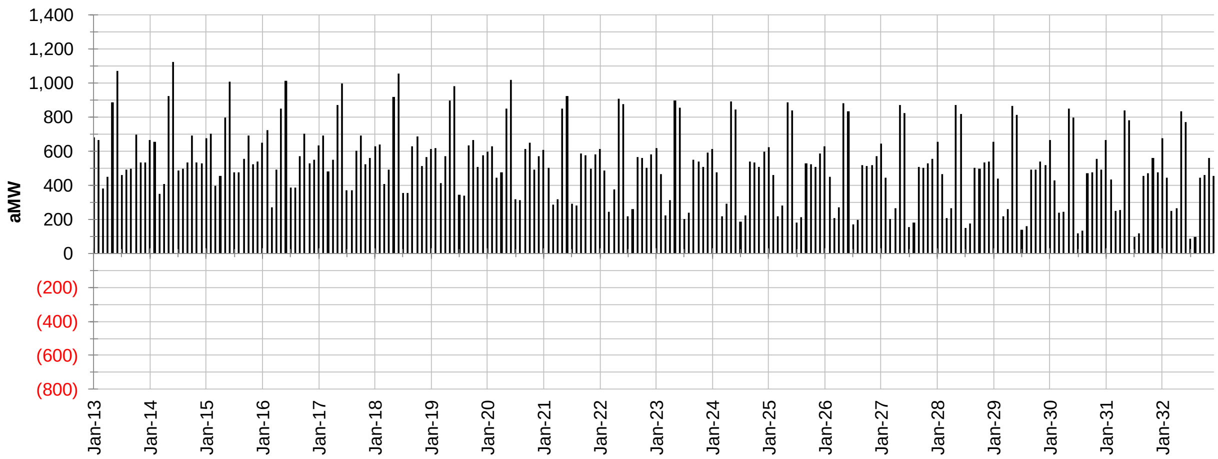


Figure 5.4 Monthly average-energy surpluses and deficits with existing and committed resources and existing DSM (70th-percentile water and 70th-percentile load)

Energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy. Peak-hour capacity continues to be the resource need in the 2013 IRP.

Peak-Hour Planning

Peak-hour load deficits are determined using 90th-percentile water and 95th-percentile peak-hour load conditions. In addition to the peak-hour criteria, 70th-percentile average load conditions are analyzed for the average-energy load and resource balance. 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.

Idaho Power's customers reach a maximum energy demand in the summer. Idaho Power's existing and committed resources are insufficient to meet the projected peak-hour growth, and the company's customers in Oregon and Idaho face significant capacity deficits in the summer months if additional resources are not added.

At times of peak summer load, Idaho Power is using all available transmission capacity (ATC) from the Pacific Northwest. If Idaho Power was to face 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.

Figure 5.5 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 5.5 also include the forecast effect of existing energy efficiency programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade once it is available. Idaho Power assumes the existing PURPA projects will continue to deliver energy throughout the planning period unless the project developer has notified Idaho Power that the PURPA project intends to cease energy deliveries. Idaho Power assumes the existing PURPA projects will develop new contracts consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. The import capacity from the Boardman to Hemingway transmission line and the demand reduction due to the demand response programs are not included in Figure 5.5.

The first capacity deficit begins in July 2016, and monthly peak-hour deficit positions grow steadily in magnitude and the number of months affected. By July 2032, these capacity deficits are approximately 870 MW.

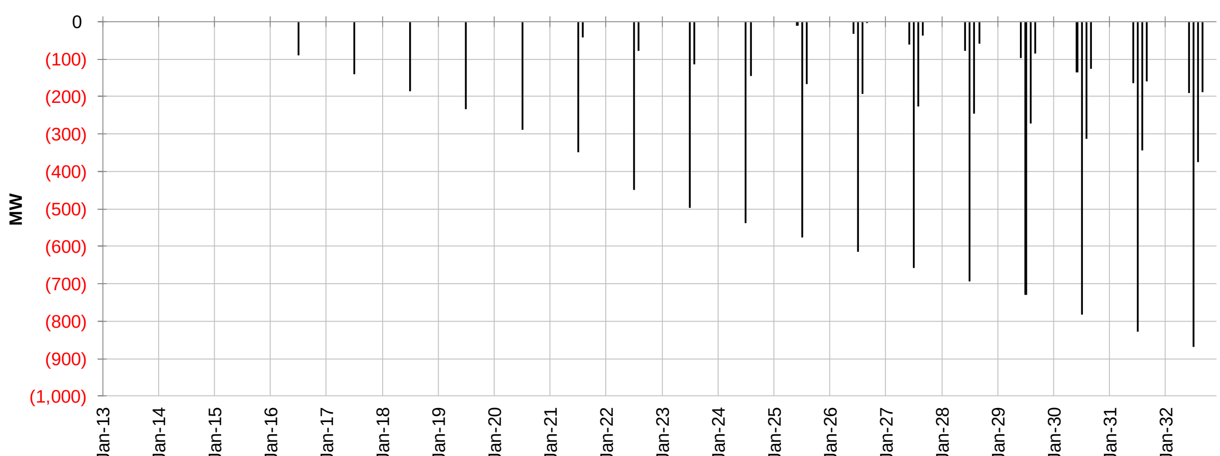


Figure 5.5 Monthly peak-hour deficits without existing and committed resources and existing DSM (90th-percentile water and 95th-percentile load)

Capacity and energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 5.5 were used to design the portfolios analyzed in the 2013 IRP.

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. The IPUC has recently ruled on avoided cost rate methodologies (Case No. GNR-E-11-03, Order No. 32697; December 18, 2012). In the order, the IPUC stated the following (page 16):

> *We further find that, in order to remain flexible and responsive to the fluctuations in gas prices, it is appropriate to annually update the SAR model with the most recent gas forecasts provided by EIA's Annual Energy Outlook.*

Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast for IRP and avoided-cost calculations. The *Annual Energy Outlook 2012* Reference case was published by the EIA in June 2012, and Idaho Power used the *Annual Energy Outlook 2012* forecast for the 2013 IRP. A graph of the forecasted Henry Hub natural gas prices is shown in Figure 5.6. Idaho Power computed a high and low natural gas price forecast by adjusting the EIA natural gas price forecast upward and downward by 30 percent. The high and low forecasts are also shown in Figure 5.6. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city-gate price. The Idaho city-gate price is representative of the gas price delivered to the Idaho Power gas plants.

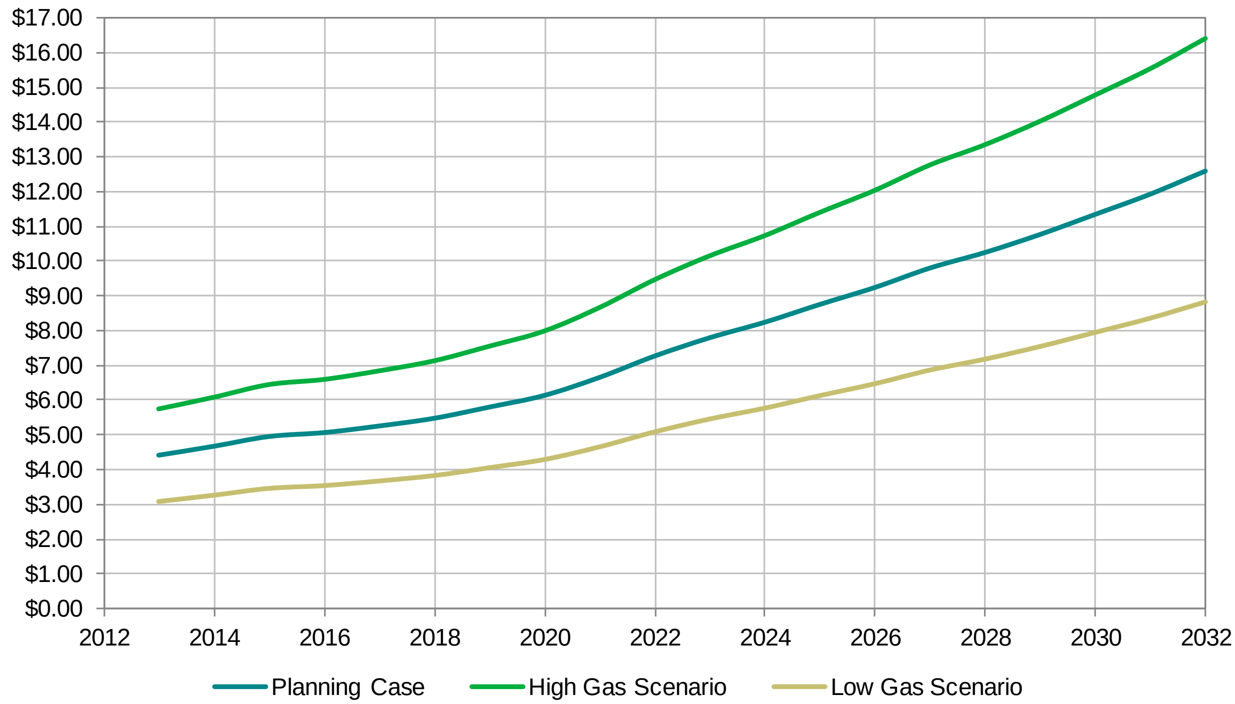


Figure 5.6 Henry Hub Price Forecast—EIA *Annual Energy Outlook 2012* (nominal dollars)

Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2013 IRP. Cost inputs and operating data used to develop the resource cost analysis are primarily derived from NREL's *Cost and Performance Data for Power Generation Report* from February 2012. Idaho Power engineering studies and plant operating experience were also utilized. Resource costs are presented as follows:

- *30-year levelized capacity (fixed) costs*—Levelized fixed cost per kW of installed (nameplate) capacity per month

- *30-year levelized cost of production (at stated capacity factors)*—Total levelized cost per MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the capital cost of supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, applicable balance of plant construction costs, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system upgrade costs were estimated by Idaho Power's transmission planning group and were included in the total portfolio cost. The capital costs also include 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 levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, 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 shown in *Appendix C—Technical Appendix*.

Emissions Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil-fuel based generating resources are particularly sensitive to certain environmental and social costs. It is likely that additional emissions regulations will be implemented during the period covered in the 2013 IRP.

In the levelized resource cost analysis, Idaho Power incorporated an estimate for the future cost of CO_2 emissions in the overall cost of the various fossil fuel-based resources beginning in 2018. Additional information regarding the cost of carbon emissions is provided in the next section. Table 5.3 provides the emissions intensity rates assumed in the resource cost analysis and the portfolio analysis. Idaho Power assumed that new fossil fuel-based resources will be designed and built to comply with NO_x, Hg, and SO_2 regulations, and therefore emissions adders for these emission types would not be applicable.

In addition to including a CO_2 emissions adder in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for CO_2, NO_x, Hg, and SO_2 emissions for each portfolio in the 20-year planning period. For CO_2 emissions, Idaho Power assumed a CO_2 adder beginning in 2018, which affects the variable operating cost. Instead of assuming NO_x, Hg, and SO_2 emissions adders, the 2013 IRP used the Idaho Power coal study to calculate the variable and fixed environmental compliance costs attributed to each emission type. The Idaho Power coal study also performed various sensitivity analyses on NO_x, Hg, and SO_2 environmental compliance.

Table 5.3 Emissions intensity rates (pound/MWh)

			2013 Emission Rate[1] (pound/MWh)			
Plant	**Nameplate (MW)**	**Fuel**	**CO_2**	**NO_x**	**SO_2**	**Hg**
Bennett Mountain	173	Natural Gas	1,265	0.79	0.006	–
Danskin 1	179	Natural Gas	1,252	0.42	0.006	–
Danskin 2	46	Natural Gas	1,627	1.26	0.008	–
Danskin 3	46	Natural Gas	1,653	1.28	0.008	–
Langley Gulch	318	Natural Gas	799	0.06	0.004	–
Boardman	64	Coal	2,063	2.56	7.923	0.00001
Jim Bridger	771	Coal	2,182	2.03	1.529	0.00004
North Valmy	284	Coal	2,293	3.33	4.518	0.00001
IRP CCCT	300	Natural Gas	799	0.06	0.004	–
IRP SCCT	170	Natural Gas	1,265	0.79	0.006	–

[1] Approximate

Resource Cost Analysis II—Resource Stack

Levelized Capacity (Fixed) Cost

The annual fixed-revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars per kW of plant nameplate capacity per month. Included in these costs are the cost of capital and fixed O&M estimates. Figure 5.7 provides a combined ranking of all the various resource options in order of lowest to highest levelized fixed cost per kW per month. The ranking shows that distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours per year to meet peak-hour demand.

Levelized Cost of Production

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 variable operating costs. The levelized cost of production measurement represents the estimated annual cost per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 5.8. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost of production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, 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 levelized cost of production calculation for a generation resource is the assumed level of annual capacity use over the life of the resource, referred to as the capacity factor. A capacity factor of 50 percent would suggest a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost would be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity-factor assumptions reduce the MWh, and the levelized cost would be higher.

Resource capital costs are annualized over a 30-year period for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.

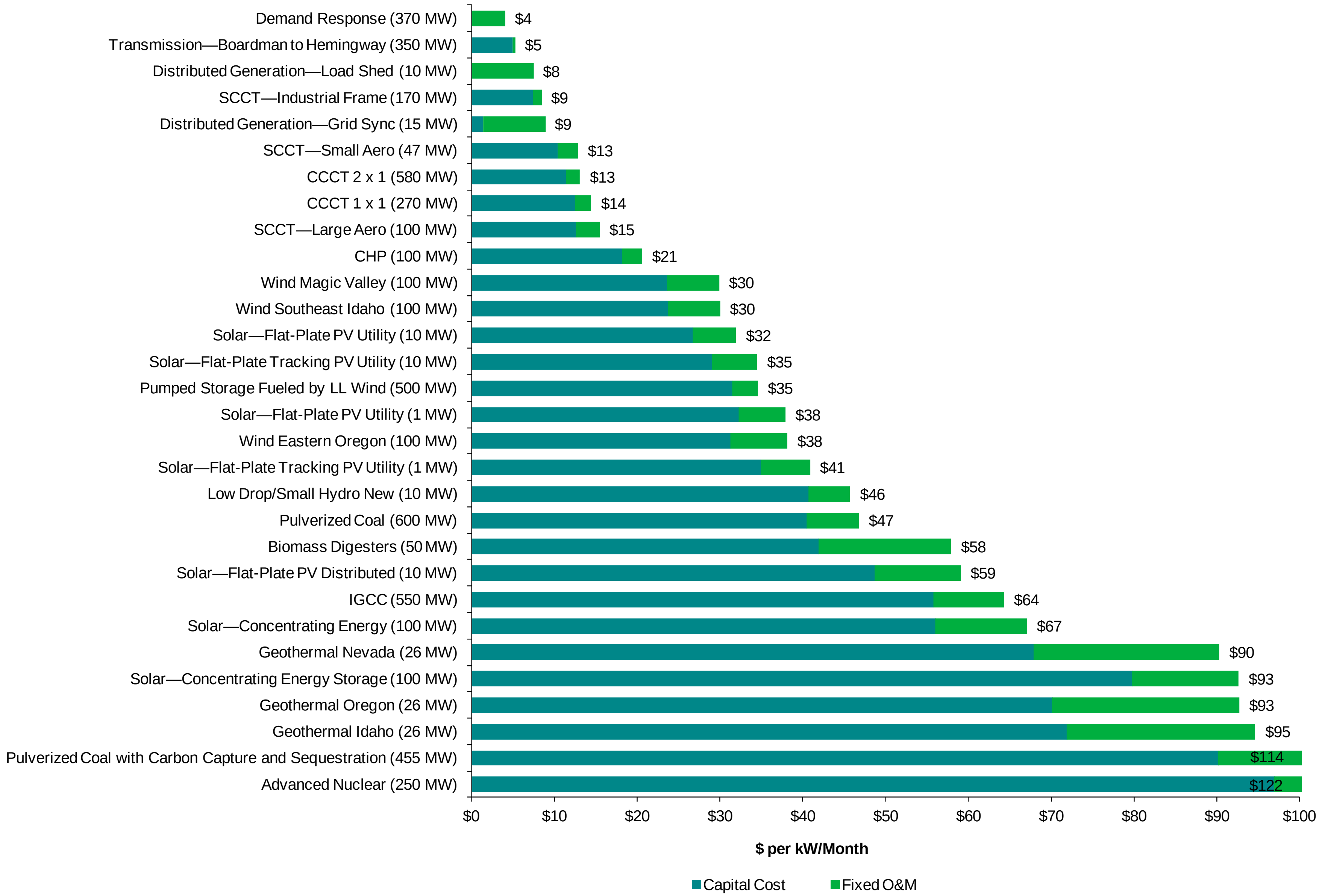


Figure 5.7 30-year levelized capacity (fixed) costs

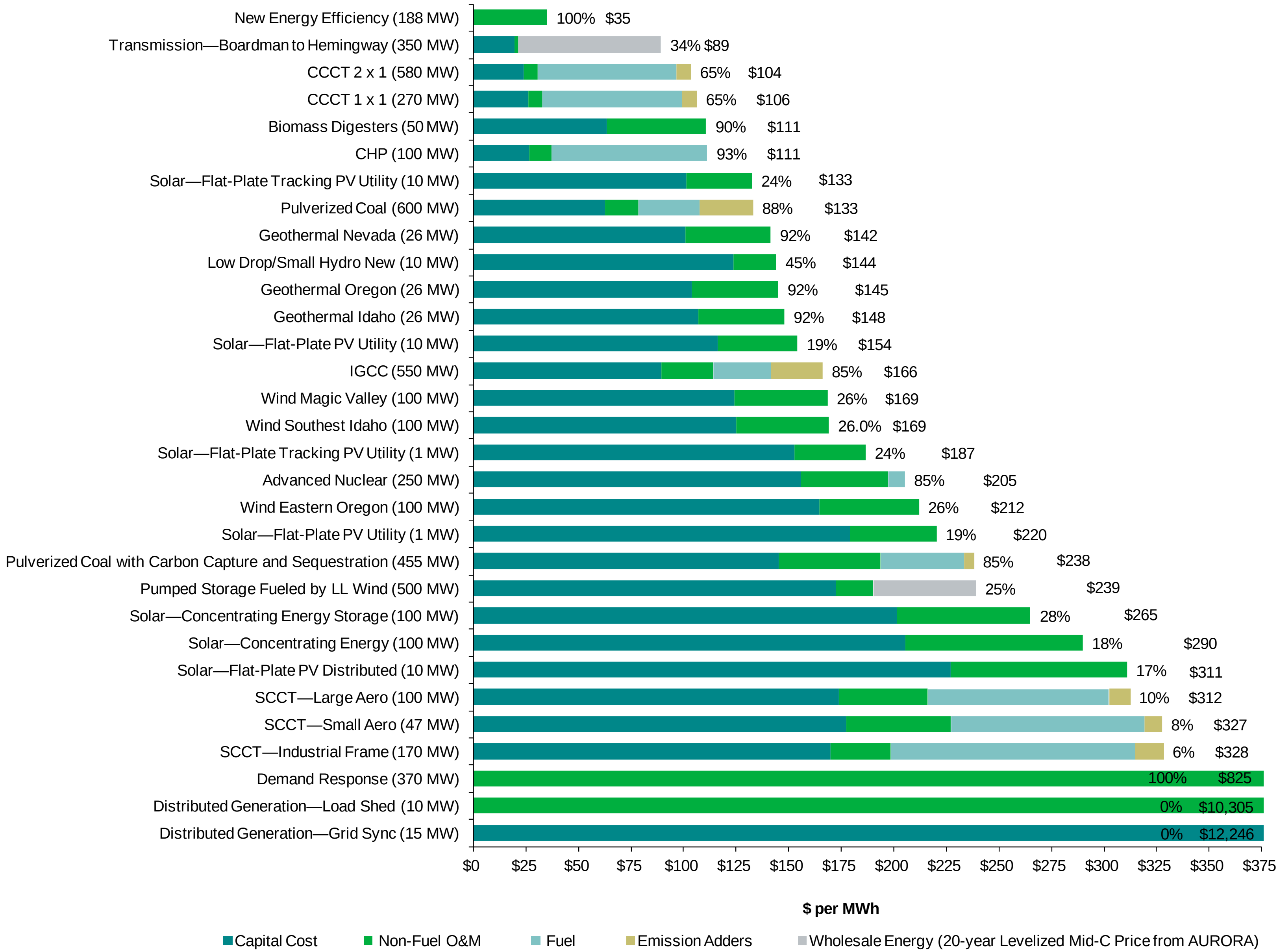


Figure 5.8 30-year levelized cost of production (at stated capacity factors)

Carbon Adder

Regulatory requirements suggest a carbon analysis be performed using a carbon adder or carbon tax. Idaho Power applied a carbon adder in the 2013 IRP. The purpose of a carbon adder is to estimate the carbon costs in the price of energy produced by carbon-emitting resources.

Three carbon-adder scenarios were analyzed as part of the 2013 IRP (in nominal dollars):

1. *Planning case*—The planning case starting at $14.64 per ton in 2018 and escalating at 3 percent annually
2. *High carbon*—The upper case starting at $35 per ton in 2018 and escalating at 9 percent annually
3. *Low carbon*—The zero-cost case where no future cost is associated with carbon emissions

Idaho Power applies a 3-percent annual escalation rate to change nominal dollars to constant-year dollars. The carbon-adder planning case is selected to be consistent with the $16-per-ton value in 2021 used in the coal study that was part of the Idaho Power 2011 IRP Update filed with the IPUC and OPUC in February 2013.

Idaho Power worked with the IRP Advisory Council to determine the three carbon scenarios. The high scenario is based in part on data from the *2011 Carbon Dioxide Price Forecast* and the *2012 Carbon Dioxide Price Forecast* published by Synapse Energy Economics, Inc., of Cambridge, Massachusetts.

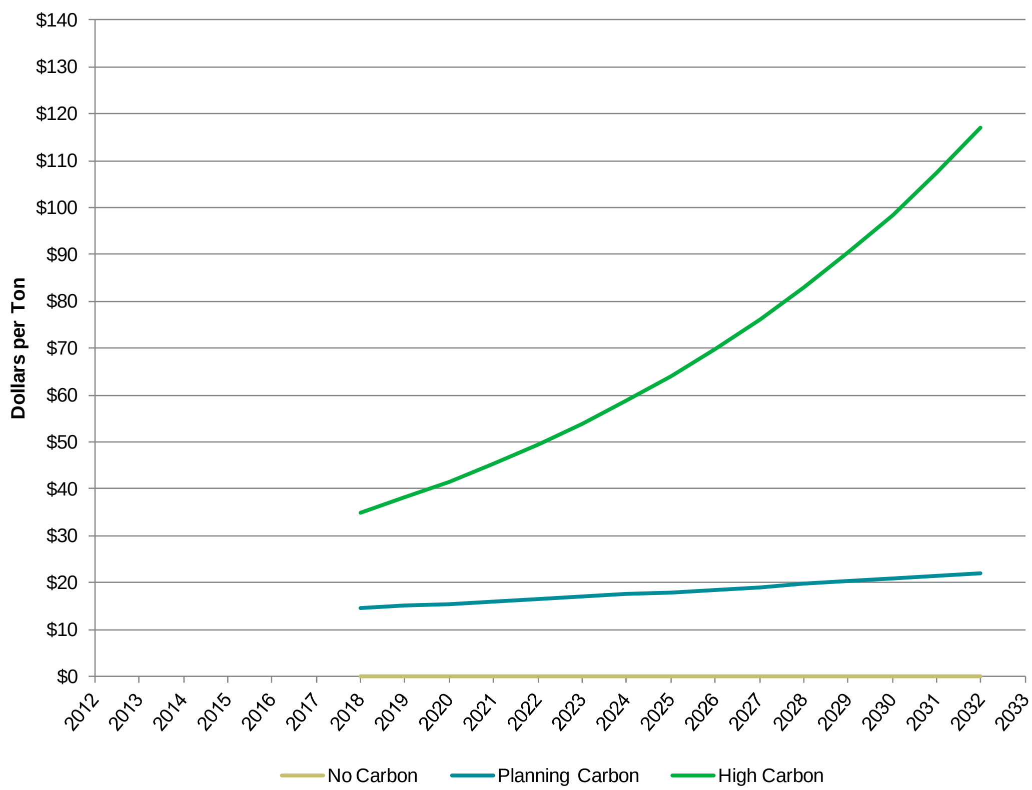


Figure 5.9 2013 IRP carbon adder

Table 5.4 Carbon-adder scenarios

	Nominal Dollars			2012 Dollars		
Year	No Carbon	Planning	Upper	No Carbon	Planning	Upper
2013	–	–	–	–	–	–
2014	–	–	–	–	–	–
2015	–	–	–	–	–	–
2016	–	–	–	–	–	–
2017	–	–	–	–	–	–
2018	$0.00	$14.64	$35.00	$0.00	$12.26	$29.31
2019	$0.00	$15.08	$38.15	$0.00	$12.26	$31.02
2020	$0.00	$15.53	$41.58	$0.00	$12.26	$32.83
2021	$0.00	$16.00	$45.33	$0.00	$12.26	$34.74
2022	$0.00	$16.48	$49.41	$0.00	$12.26	$36.76
2023	$0.00	$16.97	$53.85	$0.00	$12.26	$38.90
2024	$0.00	$17.48	$58.70	$0.00	$12.26	$41.17
2025	$0.00	$18.01	$63.98	$0.00	$12.26	$43.57
2026	$0.00	$18.55	$69.74	$0.00	$12.26	$46.11
2027	$0.00	$19.10	$76.02	$0.00	$12.26	$48.79
2028	$0.00	$19.68	$82.86	$0.00	$12.26	$51.63
2029	$0.00	$20.27	$90.31	$0.00	$12.26	$54.64
2030	$0.00	$20.88	$98.44	$0.00	$12.26	$57.83
2031	$0.00	$21.50	$107.30	$0.00	$12.26	$61.19
2032	$0.00	$22.15	$116.96	$0.00	$12.26	$64.76

Carbon-Adder Generation Dispatch Analysis

Both the 2009 and the 2011 Idaho Power IRPs indicated it would take a large carbon adder before it would be cost effective for Idaho Power to replace high CO_2-emitting resources with new generating resources that emit less CO_2. Assuming Idaho Power has already made prudent long-term resource acquisition decisions, the short-term generation dispatch decisions may vary daily resource use under certain conditions. For example, during times of the year when Idaho Power is not facing peak load and the company does not need the capacity from all generation resources, a relatively small carbon adder may affect resource dispatch decisions. A relatively small carbon adder can affect daily dispatch decisions because short-term operation decisions are primarily based on the variable costs to operate resources, whereas long-term resource acquisition decisions consider both the fixed and variable costs of the resources.

Idaho Power simulated resource dispatch conditions in 2020 as part of the 2013 IRP carbon analysis. Figure 5.10 shows that a carbon adder of approximately $5 per ton can affect the Idaho Power dispatch stack. Using 2020 planning values for fuel prices, a carbon adder over $5 per ton in 2020 may lead Idaho Power to dispatch Langley Gulch prior to dispatching the North Valmy coal plant. Figure 5.10 shows it would take a significantly higher carbon adder—over $25 per ton in 2020—before Langley Gulch has a lower dispatch cost than the Jim Bridger coal plant. Idaho Power assumed carbon adder values in 2020 of $0, $15.53, and $41.58 per ton in the 2013 IRP.

Displacing generation resources will only occur at times of low customer load. During peak seasons, it is very likely that Idaho Power will need all resources—supply side, demand side, and transmission—to meet customer load. The dispatch analysis does not suggest it is prudent or cost effective for Idaho Power to replace the coal-fired generation, but the dispatch analysis does indicate that a carbon adder may affect daily dispatch decisions under certain conditions.

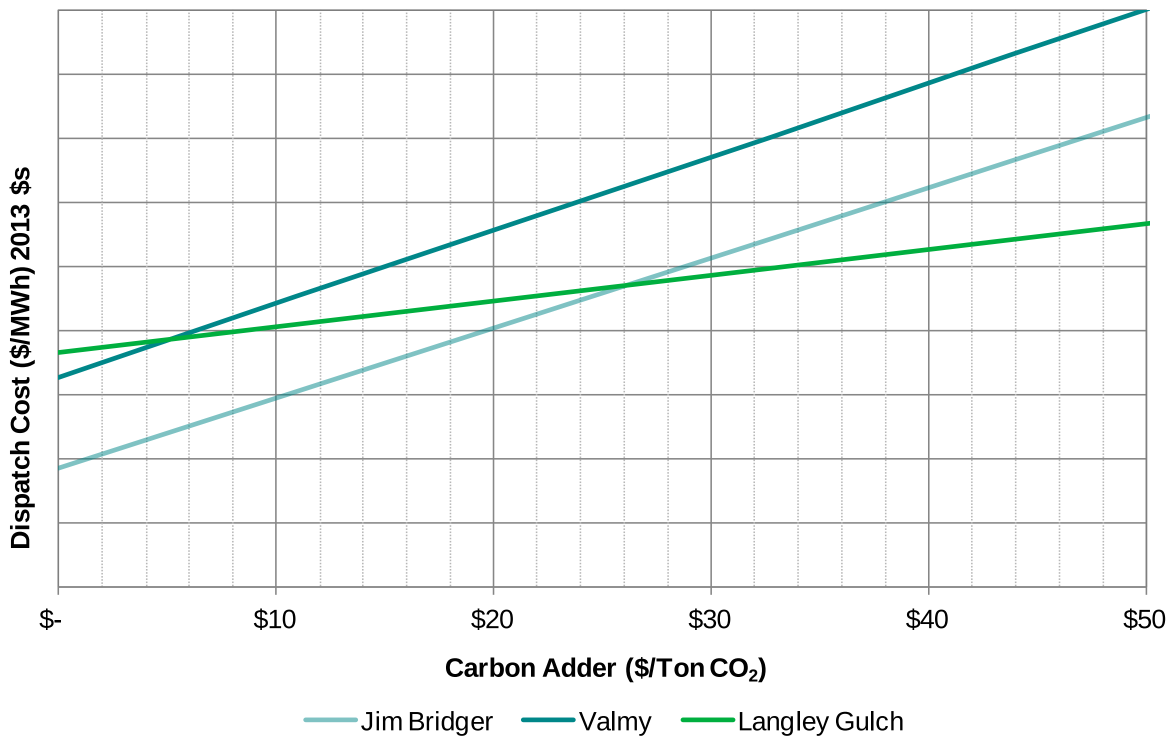


Figure 5.10 Dispatch costs, 2020

6. TRANSMISSION PLANNING

Past and Present Transmission

High-voltage transmission lines are necessary to deliver electricity to load and connect with other regional utilities.

High-voltage transmission lines have been 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 have served the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and on to the Treasure Valley were central to the development of the HCC in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three coal-fired power plants located in neighboring states that supply approximately one-third of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric resources with access to wholesale energy markets.

Idaho Power's regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of the difference in peak seasons, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load, and Idaho Power sells excess energy to Pacific Northwest utilities during the winter and spring. New regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers through the following:

- The construction of additional peaking 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.
- In general, regional transmission allows the region to share regulation and provides capacity to help integrate intermittent resources, such as wind and solar.

Transmission Planning Process

In recent years, FERC has mandated 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 Process

The expansion planning of Idaho Power's transmission network occurs through a local-area transmission advisory process and the biennial local transmission planning process.

Local-Area Transmission Advisory Process

Idaho Power develops long-term, local-area transmission plans with community advisory committees. 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 limited by the land-use plan 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 four load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Treasure Valley

Recently, the *Treasure Valley Electric Plan* was divided into two plans:

1. *Western Treasure Valley Electrical Plan*—The western plan was completed in 2011 and encompasses Malheur County in Oregon and Canyon, Gem, Owyhee, Payette and Washington counties in Idaho.

2. *Eastern Treasure Valley Electric Plan*—The eastern plan was completed in 2012 and encompasses all or portions of Ada, Elmore, and Owyhee counties in Idaho.

Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the 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 point-to-point 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.

Regional Transmission Planning

Idaho Power is active in regional transmission planning through the NTTG. The NTTG was formed in early 2007 with the overall goal of improving 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), and the Utah Associated Municipal Power Systems (UAMPS). The NTTG relies on a biennial process to develop a regional transmission plan. In preparing the regional transmission plan, the NTTG uses 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

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three distinct 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 North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission line rating process.

Existing Transmission System

Idaho Power's transmission system traverses 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 the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

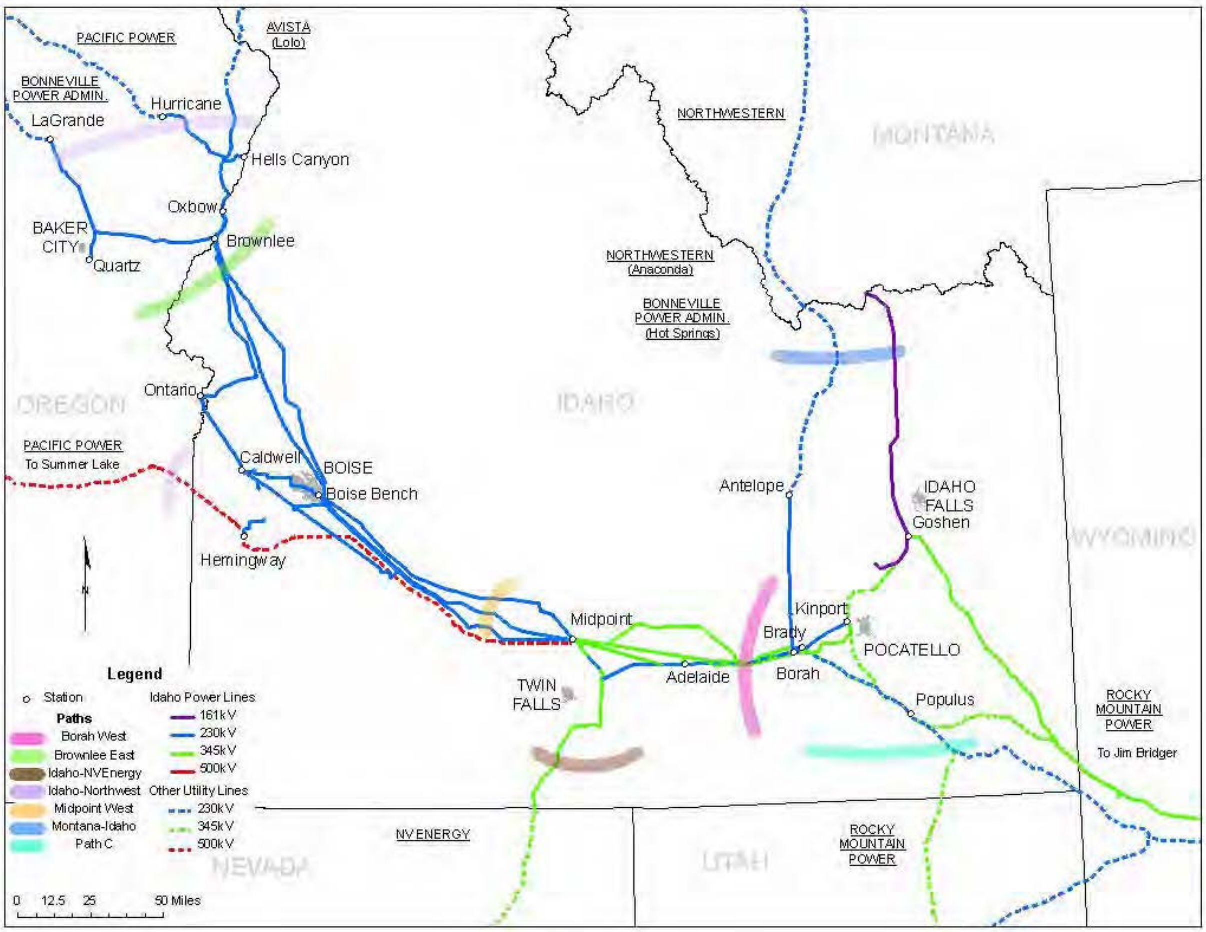


Figure 6.1 Idaho Power transmission system map

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 most likely to be capacity-limited during summer months due to transmission-wheeling obligations for the BPA eastern Oregon and southern Idaho load and due to energy imports from the Pacific Northwest to serve Idaho Power retail load. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Idaho Power 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 capacity limitation on the Brownlee East transmission path occurs between Brownlee and the Treasure Valley.

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 eastern Oregon and 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.

Idaho–Montana Path

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

Borah West Path

The Borah West transmission path is internal to the Idaho Power system. 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 east-side hydroelectric energy and energy imports from Montana, Wyoming, and Utah. PacifiCorp's two-thirds share of energy from the Jim Bridger plant also flows across this path to load centers in the Pacific Northwest. The Borah West path is capacity-limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. 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 path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. The Midpoint West path is capacity-limited due to east-side Idaho Power resources, PURPA resources, and energy imports. Similar to 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 one of the lines and is allocated 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the other two lines and is allocated 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 of the transmission lines; however, several of the lines terminate at Idaho Power-owned substations. 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 Available transmission import capacity

	Total Transmission 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	166	0
Brownlee East	West to East	1,915	0
Midpoint West	East to West	1,027	0
Borah West	East to West	2,557	0
Idaho–Wyoming (Bridger West)	East to West	2,400	60
Idaho–Utah (Path C)	South to North	1,250	0***

*Total transmission capacity and ATC as of April 1, 2013.

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

***Idaho Power estimated value, actual ATC managed by PacifiCorp.

Boardman to Hemingway

Idaho Power's IRP process has identified a transmission line to the Pacific Northwest electric market dating back to 2006. At that time, a line interconnecting at the McNary Substation to the greater Boise, Idaho, area was included in IRP portfolios. Since its initial identification, the project has been refined and developed over the years, including different terminus locations and the concept of "right sizing", or building the project to an appropriate potential. The project identified in 2006 has evolved into what is currently the Boardman to Hemingway project. The project involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and reduced capacity limitations on the regional transmission system as demand for energy grows
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon

The Boardman to Hemingway project was identified as part of the preferred portfolio in Idaho Power's 2011 IRP. Since 2011, significant progress has been made on the Boardman to Hemingway project. 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 Boardman to Hemingway project. Table 6.2 shows each party's Boardman to Hemingway capacity and permitting cost allocation.

Table 6.2 Boardman to Hemingway 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 establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two Boardman to Hemingway options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the Boardman to Hemingway project.

Considerable progress has also been made in regard to the federal and state permitting processes. The federal permitting process is established by NEPA. The Bureau of Land Management (BLM) is the lead agency in administering the NEPA process for the Boardman to Hemingway project. On May 3, 2013, the BLM announced their preliminary environmentally preferred route to the public. Figure 6.2 shows the proposed transmission line routes with the preliminary environmentally preferred route.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the Oregon Department of Energy (ODOE) as part of the state siting process. The final application is scheduled to be filed in spring 2014. As a result of the current federal and Oregon state permitting process, Idaho Power estimates that a project in-service date prior to 2018 is unlikely.

Additional project information is available at http://www.boardmantohemingway.com.

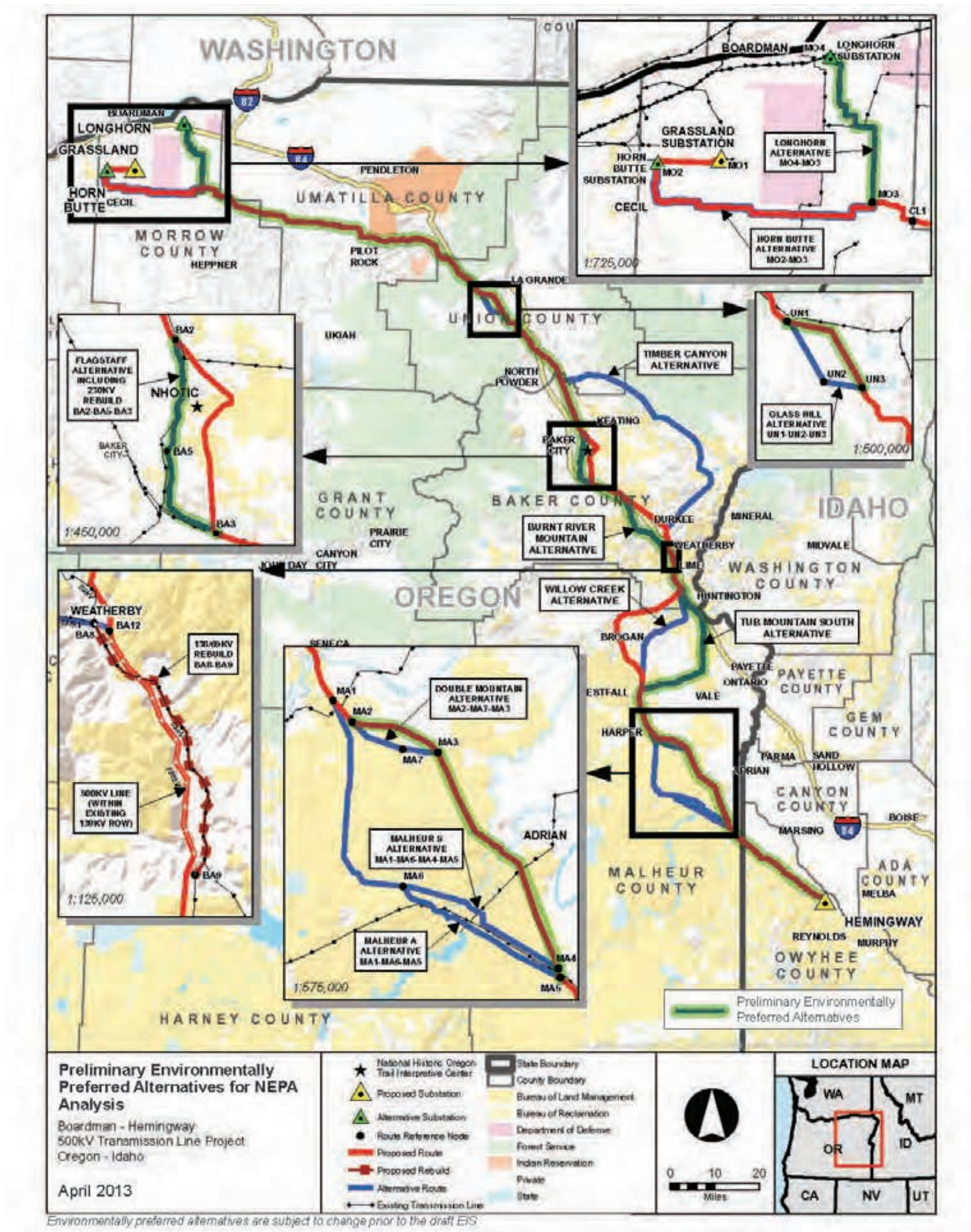


Figure 6.2 Boardman to Hemingway routes with the BLM preliminary environmentally preferred route

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power 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. Rocky Mountain Power has been designated as 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 routes studied in the federal permitting process and depicts the BLM's preferred route. 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, which is constructed as a 500 kV-line presently operating at 345 kV. The 345-kV line will be converted to 500-kV operation in the future.

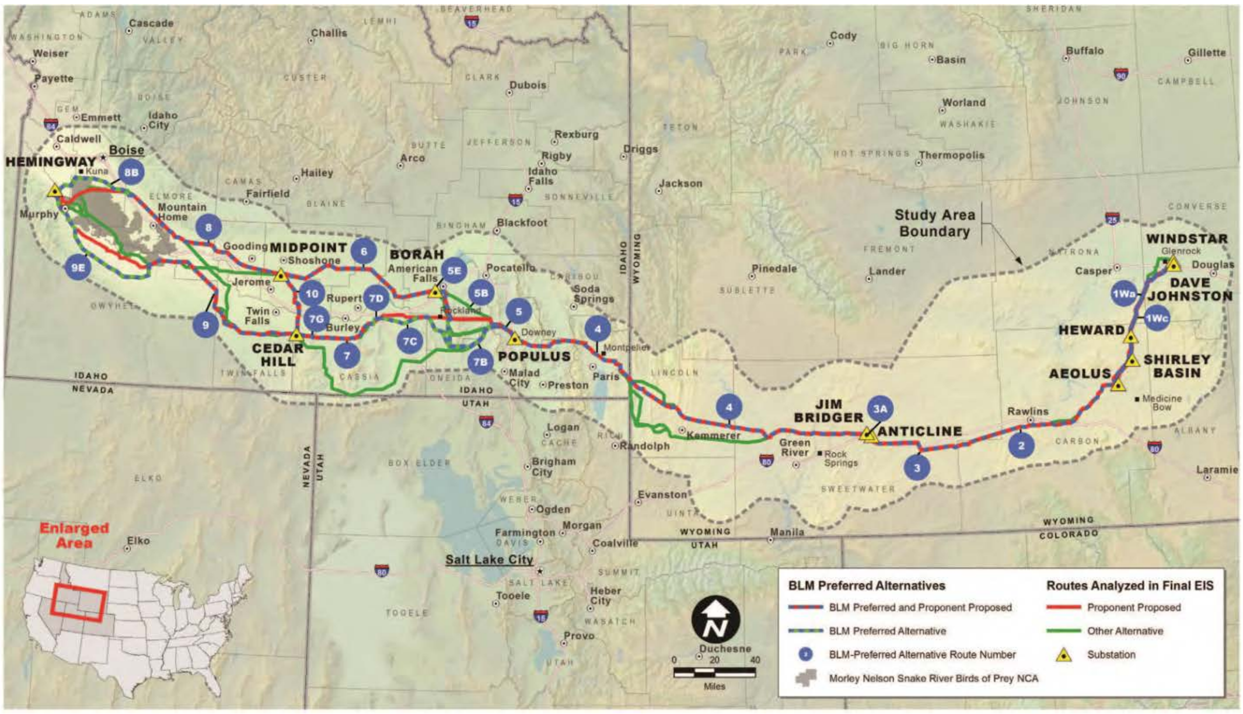


Figure 6.3 Gateway West Map

The two transmission projects, Boardman to Hemingway and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah. The new line will provide many benefits to Idaho Power customers, including the following:

- Relieve transmission constraints on the Borah West and Midpoint West paths, allowing Idaho Power to move additional energy between the east and west sides of the system.

- Provide the option to locate future generation resources east of the Treasure Valley load center.
- Provide future load service to the Magic Valley from the Cedar Hill Substation.

Phase 1 of the project is expected to provide up to 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide a total of 3,000 MW of additional transfer capacity.

The Gateway West project is currently undergoing the federal permitting process established by NEPA. The BLM is the lead agency administering the NEPA permitting process. On April 26, 2013, the BLM publically released the Final Environmental Impact Statement (FEIS) for comment. Releasing the FEIS for comment is a significant milestone in the NEPA process. A Record of Decision (ROD) is anticipated before the end of the 2013 calendar year.

The project is scheduled for line segments to be in service between 2019 and 2023. Multiple construction phases are planned to develop the transmission project by segment. The line segments from the Windstar Substation near Glenrock, Wyoming, to the Populus Substation near Downey, Idaho, are a priority for Rocky Mountain Power and are planned to be in service between 2019 and 2021.

Additional information about the Gateway West project can be found at http://www.gatewaywestproject.com.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine the 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 Hemingway Substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

Table 6.3 Transmission assumptions

Resource Type	Geographic Area	Resource Levels (per portfolio)	Additional Transmission Requirements
Boardman to Hemingway Line	Hemingway Substation	500 MW	New 230-kV line from Hemingway into the Treasure Valley.
Gas Turbines[1]	Payette County	0 MW–170 MW	Upgrade of approximately 9 miles of existing transmission into the Treasure Valley.
	Payette County	170 MW–300 MW	Rebuild an existing 230-kV line.
	Elmore County	>300 MW	Additional 230-kV line(s) into the Treasure Valley, possibly requiring different geographic locations for the resources.
Combined heat and power (CHP)	Canyon County	0 MW–100 MW	No transmission upgrades required.

[1] Coal replacement resources are assumed at or near the existing coal generation facilities.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. An analysis of the transmission capacity required from the new resources to the growing Treasure Valley load center was conducted for each portfolio. The analysis assumed that CCCT gas turbines identified to replace coal resources are located at or near the existing coal generation facilities. The transmission capacity analysis of the portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

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7. Resource Alternatives Analysis

Idaho Power conducted a resource portfolio design workshop with the IRP Advisory Council on November 30, 2012. At the portfolio design workshop, members of the IRP Advisory Council suggested Idaho Power explore a variety of resource alternatives. Members of the IRP Advisory Council commented that the method to compare resources used in earlier resource plans often paired resources, making it difficult to isolate the characteristics of a single resource alternative.

Based on the comments of the IRP Advisory Council at the portfolio design workshop, Idaho Power decided to perform a preliminary resource analysis to isolate the effects of each resource. Idaho Power performed an analysis of the following eight resources:

1. Northwest transmission
2. SCCT
3. CCCT
4. CHP
5. Pumped storage fueled by LL Wind
6. Canal drop hydroelectric
8. Utility solar PV
9. Distributed solar PV

Idaho Power assumed the same time period—2013 through 2022—the same set of existing resources, the same load forecast, the same set of planning criteria, and added the same quantity of 200 MW of on-peak capacity of each resource type. Idaho Power then conducted eight Aurora simulations of the Idaho Power system to isolate the characteristics of each resource type.

Even though the on-peak capacity of 200 MW was selected for the test, 200 MW may not be a feasible generation quantity. The alternative resource portfolios were designed only as a comparison test and were not designed to either meet load or be constructed. For example, the transmission distance to the Northwest energy market requires a greater transfer capacity than 200 MW. In each resource case, the resource costs were scaled using a linear function to estimate the costs of 200 MW of on-peak capacity for the resource alternatives analysis.

Idaho Power uses a 90-percent exceedance value to calculate the nameplate generation necessary to achieve the on-peak capacity contribution. The 90-percent exceedance value means the resource is expected to deliver the on-peak contribution during the peak hours 9 times out of 10. The 90-percent exceedance method was first applied to hydroelectric generation in the 2002 Idaho Power IRP, and it has been the standard since. The nameplate capacity of many of the resource types must exceed 200 MW to achieve 200 MW of on-peak capacity. A summary of the costs is shown in Table 7.1. Figure 7.1 shows the relative costs per delivered on-peak kW; the most cost-effective resource is Northwest transmission, followed closely by natural gas combustion turbines.

Table 7.1 Resource alternatives to achieve 200 MW of peak-hour contribution in 2018 (NPV years 2013–2022, 2013 dollars, 000s)

Resource Alternative	Peak-Hour Capacity (90% exceedance)	2018 Peak-Hour Deficit Target (MW)	Installed Nameplate Needed to Meet 200 MW Peak	Variable Costs (Aurora)	RECs Sold (reflected in variable costs)	Fixed Costs (plant, transmission, fixed O&M, & rate of return)	New Natural Gas Pipeline Capacity Charge	Total	Lowest Cost Rank	Lowest Cost Relative Difference
1—Northwest transmission	100%	(200)	200	$2,674,610	N/A	$33,039	–	$2,707,650	1	$0
2—SCCT	95%	(200)	211	$2,677,067	N/A	$79,331	$7,152	$2,763,549	2	$55,900
3—CCCT	95%	(200)	211	$2,646,794	N/A	$134,786	$38,377	$2,819,957	3	$112,308
4—CHP	95%	(200)	211	$2,644,909	$5,964	$192,212	$34,461	$2,871,582	4	$163,932
5—Pumped storage fueled by LL wind	100%	(200)	200	$2,677,703	$10,332	$311,842	–	$2,989,545	5	$281,895
6—Canal drop hydroelectric	67%	(200)	299	$2,513,007	$21,104	$603,920	–	$3,116,927	6	$409,277
7—Utility solar PV	32%	(200)	625	$2,514,873	$17,589	$882,286	–	$3,397,159	7	$689,510
8—Distributed solar PV	39%	(200)	513	$2,542,702	$14,550	$1,338,597	–	$3,881,298	8	$1,173,649

Note: Variable costs reflect the existing system plus the resource alternative. Fixed costs are representative of the resource alternative only.

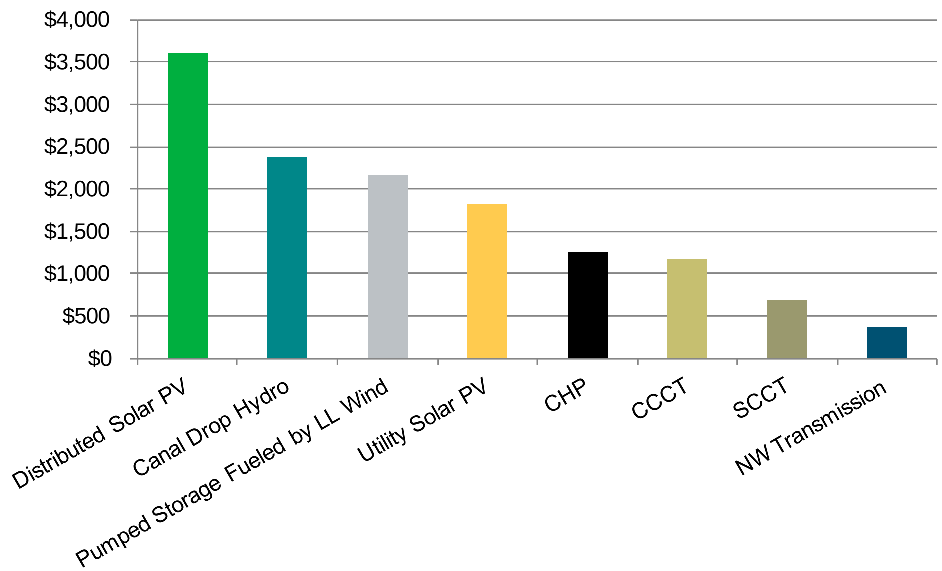

Figure 7.1 Relative costs per delivered on-peak kW

The high costs of the solar PV resources require some explanation. The Idaho Power system peak commonly occurs in the late afternoon and early evening on hot July days when A/C and agricultural pumping are near maximum use. Solar gain reaches a maximum at solar noon on the summer solstice in June. By the late afternoon and early evening hours in mid-July when Idaho Power experiences peak demand, solar gain in Idaho is considerably less—especially in the evening hours. The solar characteristics combined with the 90-percent exceedance criteria require a considerable quantity of solar generation to meet peak customer demand.

Distributed solar PV was the subject of several spirited discussions at the IRP Advisory Council meetings. Idaho Power performed a supplemental analysis of distributed PV to determine the time necessary to recover the capital investment from the perspective of an Idaho Power residential customer. Idaho Power estimated the investment recovery time period using a residential energy rate of $0.0855 per kWh, a 3-percent escalation rate, and an annual solar capacity factor of approximately 15 percent (the solar capacity factor is based on solar data from the NREL PVWatts website). The results of the analysis are shown in Figure 7.2. The figure shows the cost recovery with no tax incentives as well as the recovery with federal and state incentives. Until the installed cost with incentives drops below approximately $2 per watt, investment recovery periods exceed 10 years for residential solar PV.

The same general conclusions can be applied to utility solar PV installations. Until annual average wholesale energy prices exceed $85.50 per MWh and until the installed cost with incentives drops below $2,000 per kW, utility solar investment recovery periods are likely to exceed 10 years.

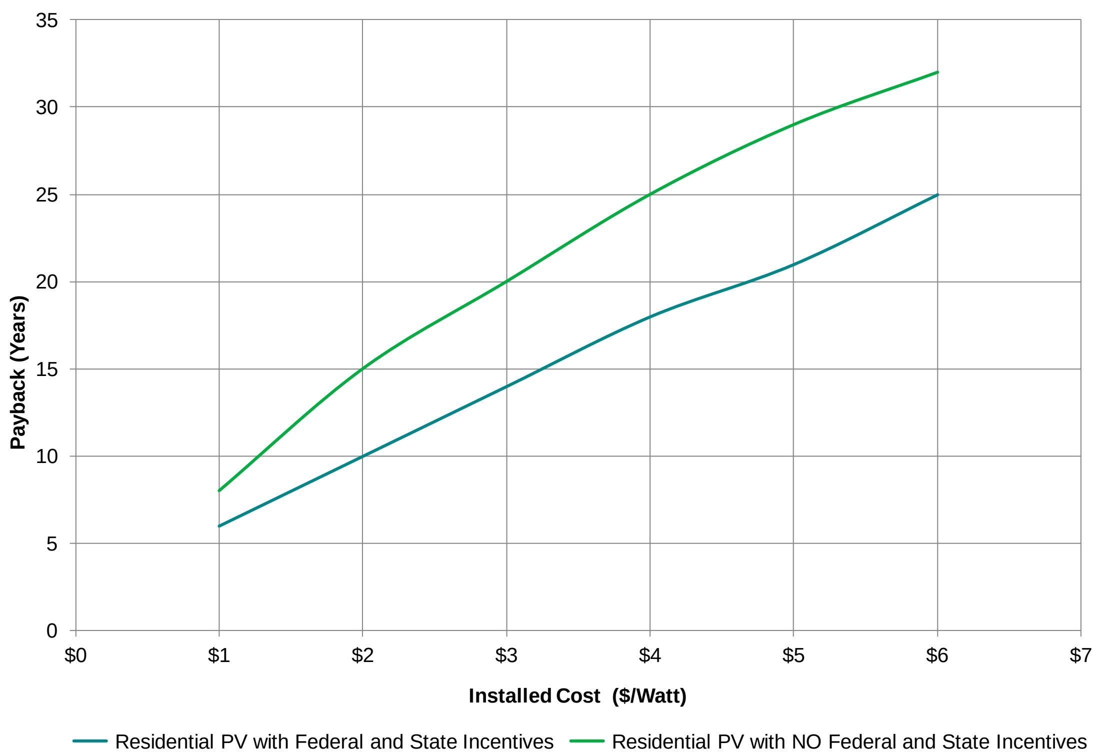

Figure 7.2 Solar generation recovery period

Idaho Power proposed a solar demonstration project as part of the 2011 IRP. The proposed project had a nameplate capacity between 0.5 and 1 MW and was initially expected to be on-line by the end of 2013.

Idaho Power is still interested in developing a solar demonstration project. With the recent issues surrounding PURPA in Idaho, the timing has not been suitable for Idaho Power to pursue the construction of a small-scale solar project. Idaho Power is required to comply with the requirements identified in the Oregon Solar Incentive Program, which include building a 500-kW, utility-scale solar facility by 2020 (Oregon House Bill 3039). Idaho Power will continue to evaluate the solar demonstration project and the benefits of receiving double RECs in the Oregon if the project is completed by the end of 2016.

Solar Parking Lot Lighting Demonstration Project

Idaho Power and Boise-based Inovus Solar have recently entered into an agreement under which Inovus will install a Solar-Enhanced Lighting™ System in the south parking lot of Idaho Power's CHQ (the parking lot is bound by Main Street, Grove Street, 12th Street, and 13th Street). The system is designed to be a grid connected net-zero system, meaning it will generate as much energy during the day as the lights consume at night while illuminating the parking lot. An example of the light is shown in Figure 7.3.

The project provides Idaho Power with insight into the performance, technology, and potential applications of the Inovus state-of-the-art Solar-Enhanced Lighting System. Additionally, the Idaho Power project provides Inovus a local installation to evaluate the performance of individual components, test enhancements, and monitor and evaluate overall system performance.

The system will generate approximately 4 kW, and the new lights are scheduled to be in service by late July 2013.

Figure 7.3 Inovus solar light

Risk Analysis and Results

Idaho Power also performed a risk analysis on the eight resource alternatives. The risk analysis is a quantitative scenario analysis. Idaho Power identified four variables for the risk analysis—the natural gas price, customer load, hydroelectric conditions, and carbon adder. In total, using the four risk variables, the following seven risk scenarios were tested:

1. High carbon adder
2. Low carbon adder
3. High gas prices

4. Low gas prices
5. Low water conditions
6. High gas prices plus low water conditions
7. High gas prices plus low water conditions and a high carbon adder

Scenarios six and seven are combinations of the risk variables designed to test more severe conditions.

The ranking of the resource alternatives under each of the seven scenarios is presented in Table 7.2 (the full costs for the different scenarios are reported in *Appendix C—Technical Appendix*).

Table 7.2 Risk scenario results

	Risk Scenario						
	Carbon		Natural Gas Price				
Resource Alternative	High	Low	High	Low	Low Water	Scenario 6	Scenario 7
Northwest transmission	1	1	1	1	1	1	1
SCCT	2	2	2	2	2	2	2
CCCT	3	3	3	3	3	3	3
CHP	4	4	4	4	4	4	4
Pumped storage fueled by LL wind	5	5	5	5	5	5	5
Canal drop hydroelectric	6	6	6	6	6	6	6
Utility solar PV	7	7	7	7	7	7	7
Distributed solar PV	8	8	8	8	8	8	8

Northwest transmission was the lowest-cost resource alternative in all scenarios, and the ranking of the resource alternatives did not change in any scenario; the low cost resources were low cost in all seven risk scenarios, and the high cost resources were high cost in all seven risk scenarios.

Based on the suggestions of the IRP Advisory Council and the results of the resource alternatives analysis, Idaho Power designed resource portfolios using the lowest-cost resource alternatives—Northwest transmission and generation fired by natural gas. The specific resource portfolios are described in the following chapter.

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8. Planning Criteria and Portfolio Selection

Planning Scenarios and Criteria

Idaho Power conducted a systematic analysis to select the preferred resource portfolio. The planning scenarios can be grouped into three main categories:

1. *Boardman to Hemingway resource portfolios*—Two resource portfolios rely primarily on the Boardman to Hemingway transmission line to meet future resource needs. The two resource portfolios contain the existing and committed Idaho Power generation resources.

2. *Alternative to Boardman to Hemingway resource portfolios*—Three resource portfolios explore alternatives to the Boardman to Hemingway transmission line to meet future resource needs. The Boardman to Hemingway transmission line is not included in the three resource portfolios. The three resource portfolios contain the existing and committed Idaho Power generation resources.

3. *Coal alternative resource portfolios*—Four resource portfolios explore options to reduce coal-fired generation in the Idaho Power resource portfolio. The options to reduce the reliance on coal include replacement with natural gas-fired generation; increased demand-side measures, including demand response; changing the fuel at the North Valmy plant to natural gas; and the Boardman to Hemingway transmission line. The alternatives to coal resource portfolios are an extension of the coal study Idaho Power included with the 2011 IRP Update.

Demand response is included in many of the resource portfolios. Idaho Power applied demand response in 50 MW increments in the resource portfolios. The lines shown on the resource portfolio graphs identify the maximum level of demand response. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The demand response 2016 level was estimated to be 100 MW and the 2017 level was estimated to be 150 MW.

The four resource portfolios that explore options for reducing coal-fired generation at Idaho Power are the first IRP portfolios in which Idaho Power has considered the early retirement of a generating resource in an IRP. Resource retirement raises a few issues unique to the 2013 IRP. Specifically, resource retirement portfolios require Idaho Power to consider the remaining asset value of the resource and to include recovering the asset value in the resource portfolio. In addition, resource retirement also requires Idaho Power to account for any retirement and termination costs when estimating the resource portfolio costs.

Resource retirement also requires Idaho Power to estimate the ongoing capital requirements of the coal-fired resources and to include the ongoing capital requirements in the resource portfolios containing the existing resources. Treatment of the fixed-cost accounting is summarized in Table 8.1.

Table 8.1 Coal resource fixed-cost accounting

Capital Description	Existing Coal Resource Portfolios	Coal Replacement Resource Portfolios
Coal Emission-Control Equipment	Included	Excluded
Existing Coal Resources	Included	Excluded
Replacement Resources	Excluded	Included
Accelerated Recovery of Existing Coal Plant Investment	Excluded	Included
Decommissioning Coal Asset	Excluded	Included

The word *included* indicates costs must be added to the resource portfolio costs, and *excluded* indicates no additional costs. For example, the cost of the emission-control equipment must be added to the resource portfolios that use the existing coal plants, whereas the resource portfolios that replace coal will not incur the emission-control equipment costs. Each of the nine detailed resource portfolios analyzed are described in the next section.

Portfolio Design and Selection

The following resource portfolios are described in tables 8.2 through 8.10, which list the resource types, implementation dates, and on-peak capacity. Figures 8.1 through 8.9 show monthly peak-hour deficits under 90th-percentile water and 95th-percentile load with existing and committed resources and existing energy efficiency programs. When a new resource is added, a horizontal line on the chart shows the capacity contribution of the new resource.

Boardman to Hemingway Resource Portfolios

Resource Portfolio 1—Boardman to Hemingway plus Demand Response and an SCCT

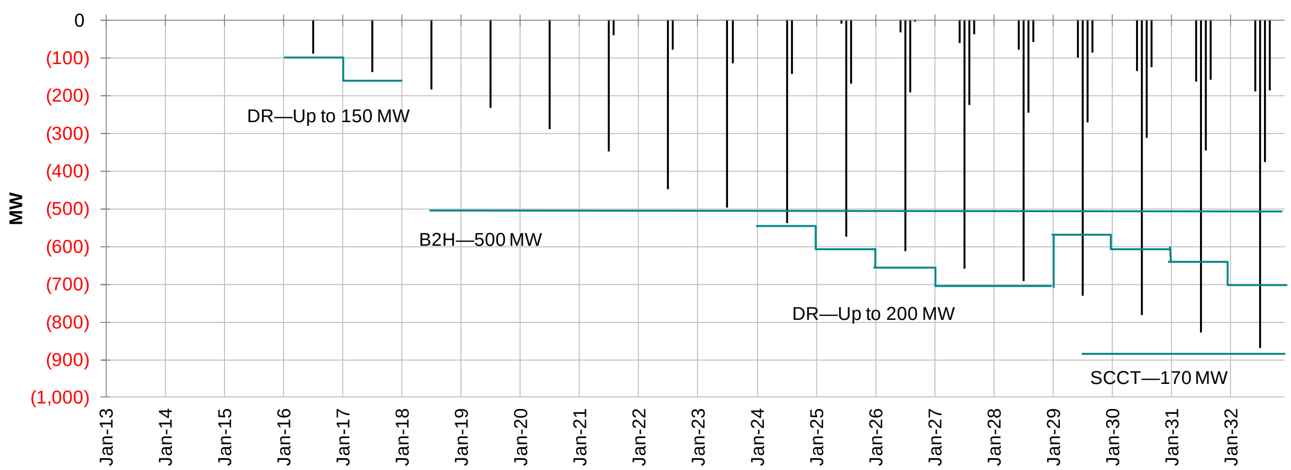

Figure 8.1 Resource portfolio 1

Table 8.2 Resource portfolio 1

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Summer 2024	Demand response	Up to 200 MW in 50-MW increments
Summer 2029	SCCT	170 MW

Resource Portfolio 2—Boardman to Hemingway plus Demand Response

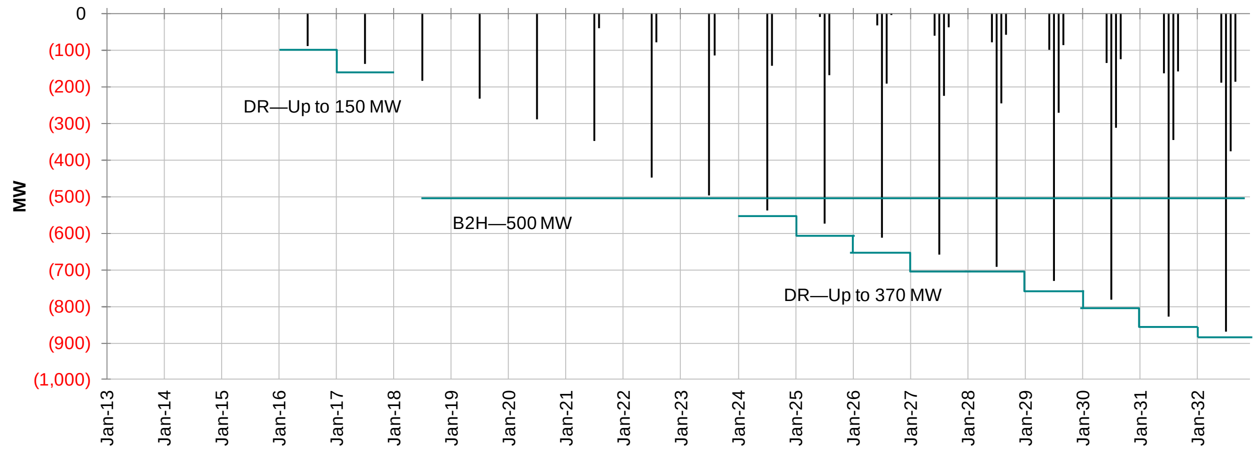

Figure 8.2 Resource portfolio 2

Table 8.3 Resource portfolio 2

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Summer 2024	Demand response	Up to 370 MW in 50-MW increments

Alternative to Boardman to Hemingway Resource Portfolios

Resource Portfolio 3—Demand Response plus a CCCT and an SCCT

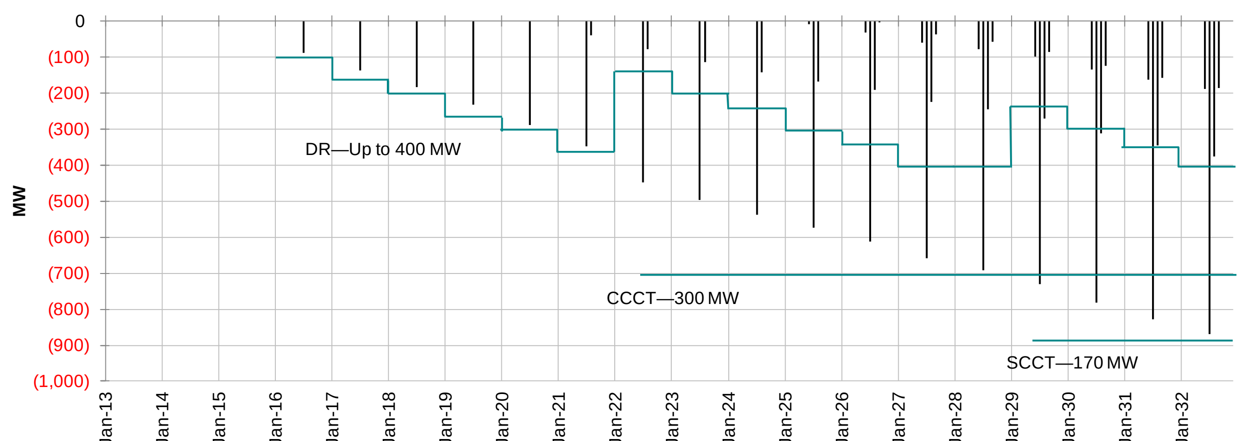

Figure 8.3 Resource portfolio 3

Table 8.4 Resource portfolio 3

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	Demand response	Increasing to 400 MW in 50-MW increments
Summer 2022	CCCT	300 MW
Summer 2029	SCCT	170 MW

Resource Portfolio 4—Demand Response plus Two CCCTs

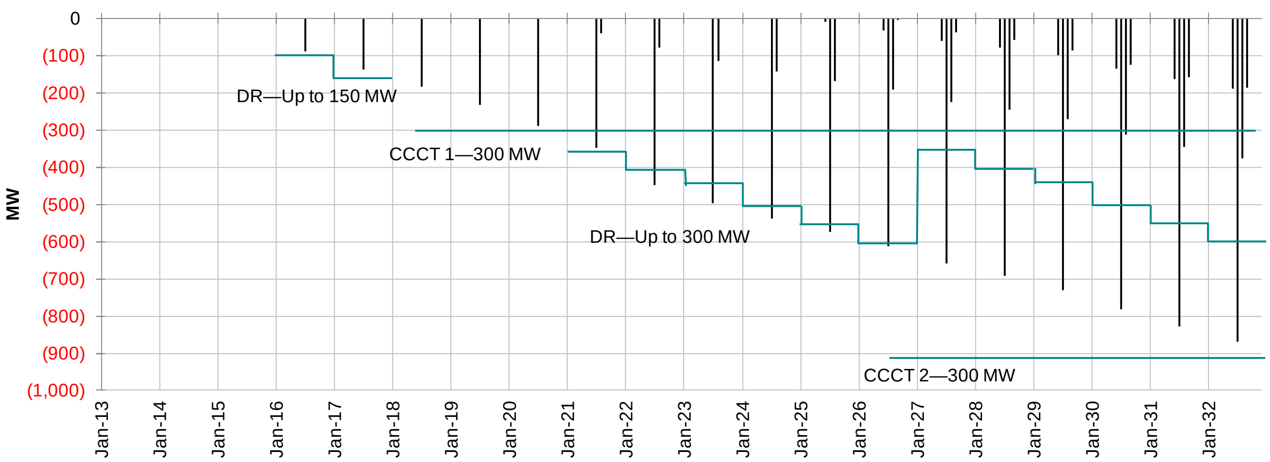

Figure 8.4 Resource portfolio 4

Table 8.5 Resource portfolio 4

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	CCCT	300 MW
Summer 2021	Demand response	Additional 300 MW in 50-MW increments
Summer 2026	CCCT	300 MW

Resource Portfolio 5—Demand Response plus Two Consecutive CCCTs

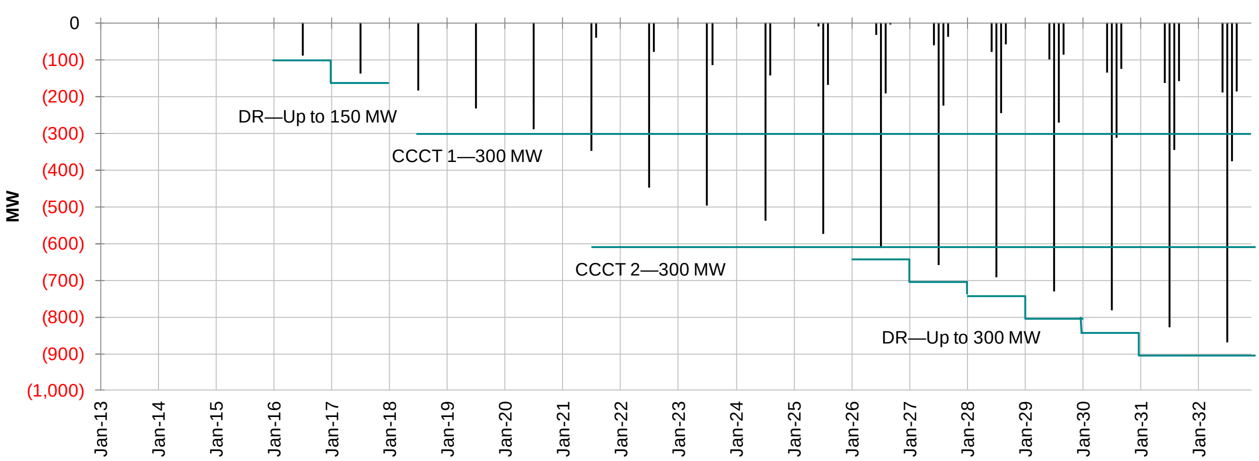

Figure 8.5 Resource portfolio 5

Table 8.6 Resource portfolio 5

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	CCCT	300 MW
Summer 2021	CCCT	300 MW
Summer 2026	Demand response	Additional 300 MW in 50-MW increments

Coal Alternative Resource Portfolios

The coal alternative resource portfolios are shown with a different monthly peak-hour load and resource balance. Figures 8.6 through 8.9 show the anticipated monthly peak-hour resource deficits in black, similar to resource portfolios 1 through 5. However, removing existing generation resources increases the monthly peak-hour capacity deficits, and figures 8.6 through 8.9 show the increased deficits created by removing coal generation in red. Resource portfolios 6 through 9 are designed to meet the increased deficits shown in red. The deficit scale in the coal alternative resource portfolios is different than the scale shown in the resource portfolios containing the existing coal resources. The monthly peak-hour deficits are under 90th-percentile water and 95th-percentile load with existing and committed resources and existing energy efficiency programs.

Resource Portfolio 6—ICL–BSU

Resource portfolio 6 was suggested by members of the Idaho Power IRP Advisory Council representing the ICL and BSU. Idaho Power worked with the two IRP Advisory Council members representing the ICL and BSU to refine the resource portfolio.

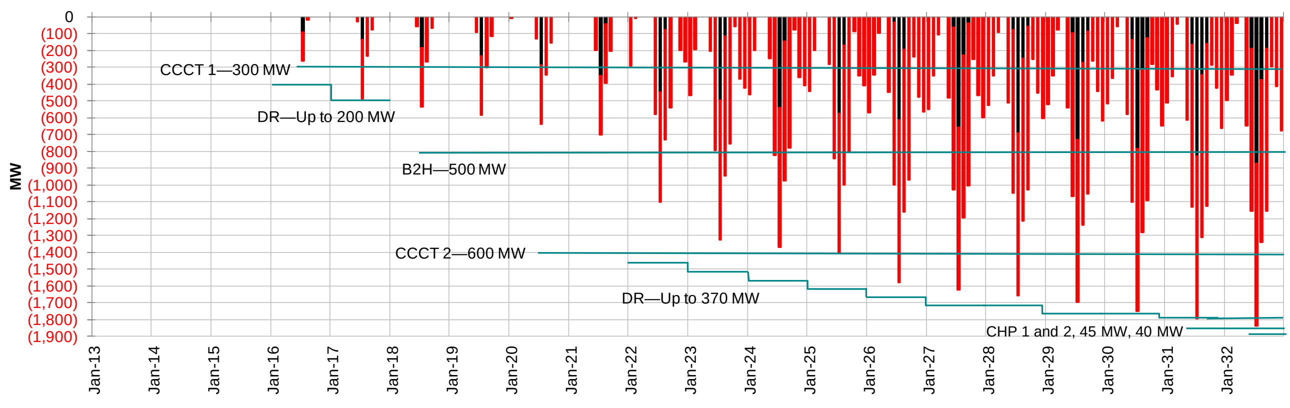

Figure 8.6 Resource portfolio 6

Table 8.7 Resource portfolio 6

Date	Resource	Capacity
Year-end 2015	Exit Bridger Unit 3 and Valmy Unit 1	Minus approximately 300 MW
Summer 2016	CCCT	300 MW
Year-end 2016	Exit Bridger Unit 4	Minus approximately 170 MW
2016–2017	Demand Response	Up to 200 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2020	Exit Bridger Units 1 and 2, Valmy Unit 2	Minus approximately 370 MW
Year-end 2020	CCCT	600 MW
Summer 2031	CHP	45 MW
Summer 2032	CHP	40 MW

Resource Portfolio 7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response

Resource portfolio 7 is based on the Idaho Power coal study presented with the 2011 IRP Update. Resource portfolio 7 replaces coal-fired generation resources with natural gas-fired generation. Specifically, the North Valmy coal plant is modified to burn natural gas and the Jim Bridger plant is replaced with CCCTs fired by natural gas.

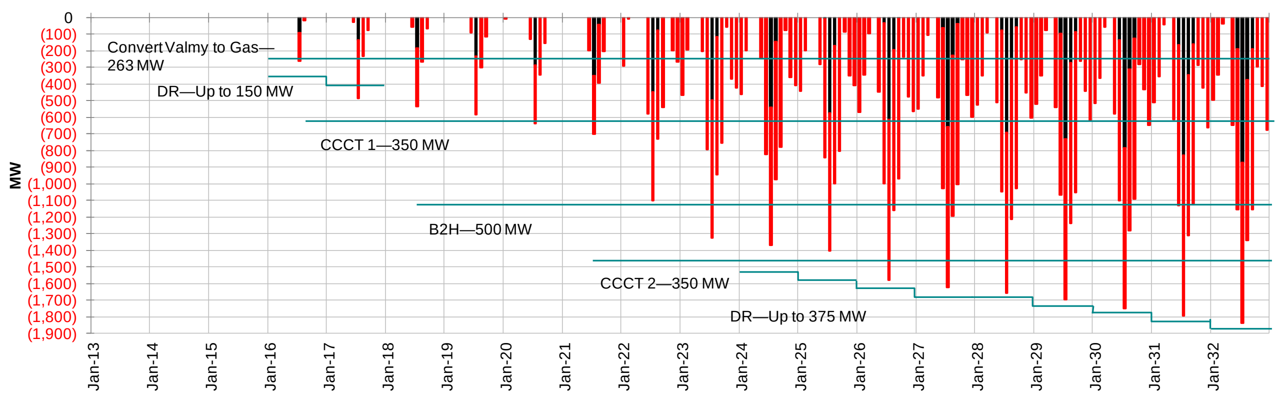

Figure 8.7 Resource portfolio 7

Table 8.8 Resource portfolio 7

Date	Resource	Capacity
January 2015	Convert Valmy Units 1 and 2 to be fueled by natural gas	No Change
Year-end 2015	Cease coal-fired operation of Bridger Units 3 and 4	Minus approximately 340 MW
Summer 2016	CCCT	350 MW
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2020	Cease coal-fired operation of Bridger Units 1 and 2	Minus approximately 340 MW
Summer 2021	CCCT	350 MW
2021–2032	Demand response	Up to 375 MW

Resource Portfolio 8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT

In April 2013, NV Energy announced a schedule to retire the North Valmy Coal Plant. Idaho Power is a one-half owner of the North Valmy coal plant, and NV Energy is the operating partner. Idaho Power has not agreed to the North Valmy plant retirement schedule announced by NV Energy. Resource Portfolio 8 is designed to estimate the effects of retiring North Valmy Units 1 and 2 according to the NV Energy schedule and replacing the lost generation with demand response, Boardman to Hemingway, and a CCCT (North Valmy Unit 1 is retired at year-end 2020 and North Valmy unit 2 is retired at year-end 2025).

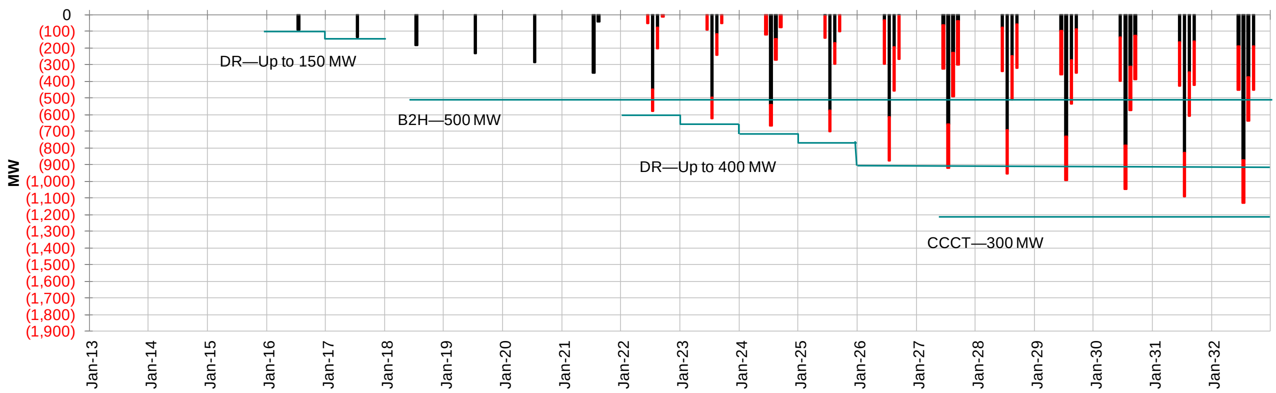

Figure 8.8 Resource portfolio 8

Table 8.9 Resource portfolio 8

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2021	Valmy 1 retired	Minus approximately 130 MW
Summer 2022	Demand response	Up to 400 MW
Year-end 2025	Valmy 2 retired	Minus approximately 130 MW
Summer 2027	CCCT	300 MW

Resource Portfolio 9—North Valmy Closure, Boardman to Hemingway Alternative

Like resource portfolio 8, resource portfolio 9 is designed to estimate the effects of retiring North Valmy on the schedule announced by NV Energy. Resource Portfolio 9 replaces the lost generation with alternatives to Boardman to Hemingway, including demand response, two CCCTs, and one SCCT.

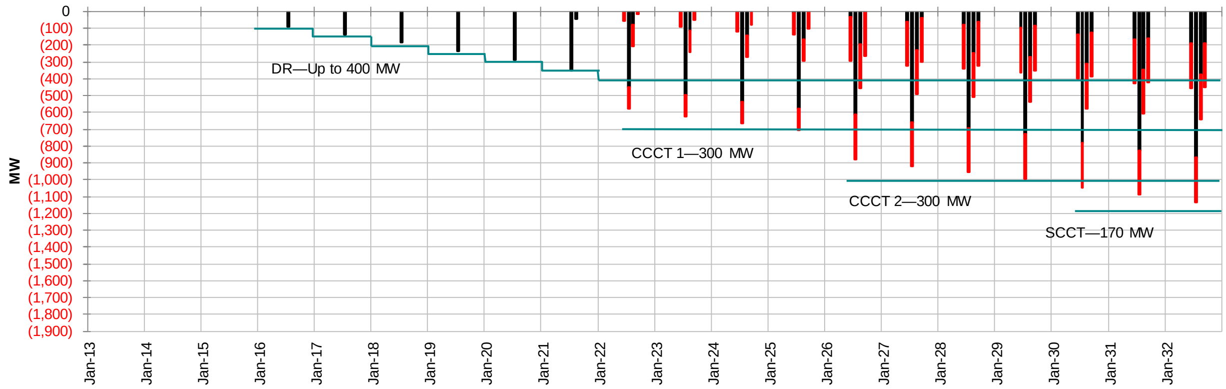

Figure 8.9 Resource portfolio 9

Table 8.10 Resource portfolio 9

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Expanded demand response	Up to 400 MW
Year-end 2021	Valmy 1 closure	Minus approximately 130 MW
Summer 2022	CCCT	300 MW
Year-end 2025	Valmy 2 closure	Minus approximately 130 MW
Summer 2026	CCCT	300 MW
Summer 2030	SCCT	170 MW

9. Modeling Analysis and Results

Portfolio Costs

Idaho Power evaluated the costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to meet the customer load using all resources in the portfolio. Resource portfolios 1 through 5 assume the continued operation of the Jim Bridger and North Valmy coal facilities. (The Boardman coal plant ceases coal-fired operations at year-end 2020 in all resource portfolios.) Idaho Power ceases coal-fired operations at the North Valmy and Jim Bridger plants in resource portfolios 6 and 7. Resource portfolios 8 and 9 retire the North Valmy plant on the schedule identified by NV Energy in April 2013. (North Valmy Unit 1 is retired at year-end 2021, and North Valmy Unit 2 is retired at year-end 2025.)

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 cost of capital)	7.00%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	3.00%
Emissions-adder escalation rate	2.50%
Carbon-adder escalation rate	5.00%
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)	7.00%
Production tax credit escalation rate	3.00%

Table 9.2 reports the total cost of each resource portfolio for the 20-year planning horizon. The total cost is the NPV of the variable operating costs plus the fixed cost of the existing, new, and replacement resources. The variable operating costs include the fuel cost, purchased-power cost, O&M, and other costs.

Table 9.2 2013 IRP portfolios, NPV years 2013–2032 (2013 dollars, 000s)

	Variable Costs	Fixed Costs				Summary		
Portfolio (1)	Operating[1] (Aurora) (2)	New Resources[2] (3)	New Natural Gas Pipeline Capacity Charge (4)	Demand Response (5)	Total (6) (3)+(4)+(5)	Total Portfolio Costs (7) (2)+(6)	Lowest Cost Rank (8)	Lowest Cost Relative Difference (9)
2—Boardman to Hemingway plus Demand Response	$4,987,003	$185,028	$0	$48,547	$233,575	$5,220,578	1	$0
1—Boardman to Hemingway plus Demand Response and an SCCT	$4,987,143	$221,699	$2,300	$34,818	$258,817	$5,245,960	2	$25,382
3—Demand Response plus a CCCT and an SCCT	$4,940,835	$351,762	$80,973	$105,933	$538,668	$5,479,503	3	$258,925
4—Demand Response plus Two CCCTs	$4,872,870	$638,016	$166,043	$52,744	$856,803	$5,729,673	4	$509,095
8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT	$5,056,695	$598,447	$38,902	$73,927	$711,276	$5,767,971	5	$547,394
5—Demand Response plus Two Consecutive CCCTs	$4,843,988	$796,666	$211,320	$35,067	$1,043,052	$5,887,040	6	$666,463
9—North Valmy Closure, Boardman to Hemingway Alternative	$4,991,277	$744,041	$139,722	$127,677	$1,011,439	$6,002,716	7	$782,138
6—ICL–BSU	$5,688,123	$650,693	$336,164	$57,771	$1,044,628	$6,732,751	8	$1,512,173
7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response	$5,789,525	$654,534	$516,133	$45,965	$1,216,632	$7,006,156	9	$1,785,578

[1] Variable operating costs reflect the existing system with coal plant shutdowns (when applicable) plus the new portfolio resources, REC sales, and carbon adder.

[2] New plant capital, new plant transmission, stranded asset value, environmental compliance upgrade (when applicable), accelerated recovery of existing coal plant investment, and decommissioning coal asset.

The resource portfolios are sorted from lowest cost to highest cost in Table 9.2. Resource portfolio 2 is the least-cost resource portfolio.

The general ranking of resource portfolios shows resource portfolios that include Boardman to Hemingway cost less than comparable resource portfolios that rely on alternatives to Boardman to Hemingway. The resource portfolios that replace resources—resource portfolios 6 through 9—are generally the most expensive options. However, resource portfolio 8, which replaces North Valmy, costs less because it includes the Boardman to Hemingway transmission line. Figure 9.1 shows the resource portfolio costs.

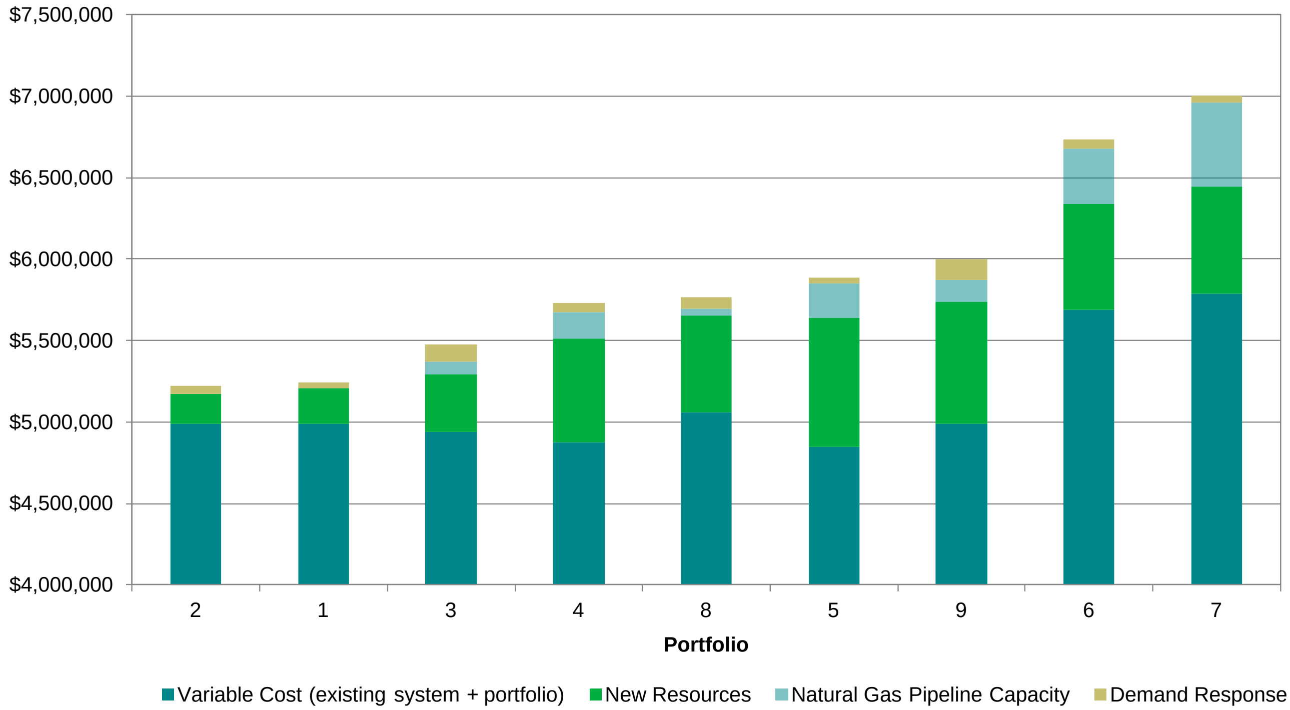

Figure 9.1 Total portfolio costs, NPV 2013–2032 (2013 dollars, 000s)

Portfolio Emissions

For the 2013 IRP, Idaho Power analyzed the total portfolio emissions for the 20-year planning period by the following four emission types:

1. CO_2—A greenhouse gas associated with climate change
2. NO_x—Contributes to regional haze
3. SO_2—Contributes to acid rain formation
4. Hg—A toxic element found in coal deposits

Total emissions by type were calculated using Aurora emissions modeling. All portfolios comply with all known environmental regulations. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing and committed resources.

CO_2 Emissions

Figure 9.2 shows the total CO_2 emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced CO_2 emissions. The reduced emissions are because a CCCT resource emits approximately 37 percent of the CO_2 per MWh that Idaho Power coal-fired generation resources emit on average.

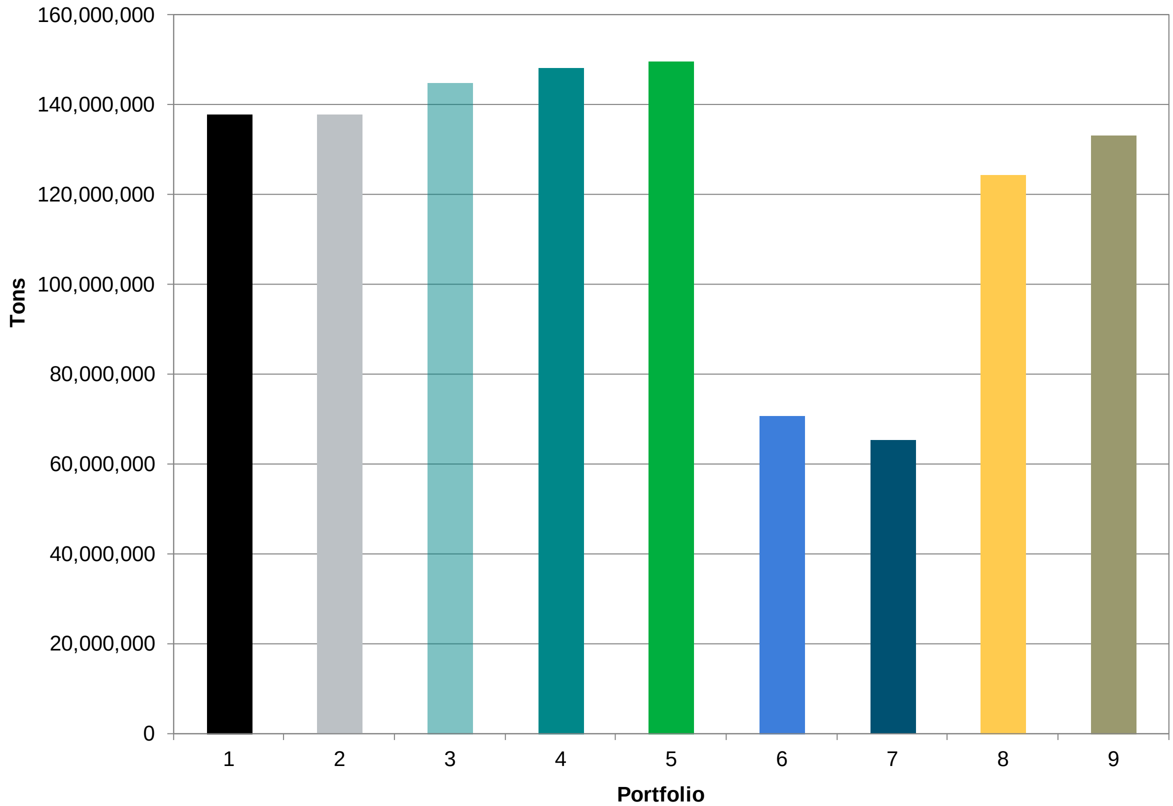

Figure 9.2 Total CO_2 emissions for 2013–2032

NO_x Emissions

Figure 9.3 shows the total NO_x emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced NO_x emissions. The reduced emissions are because a CCCT resource emits approximately 2 percent of the NO_x per MWh that Idaho Power coal-fired generation resources emit on average.

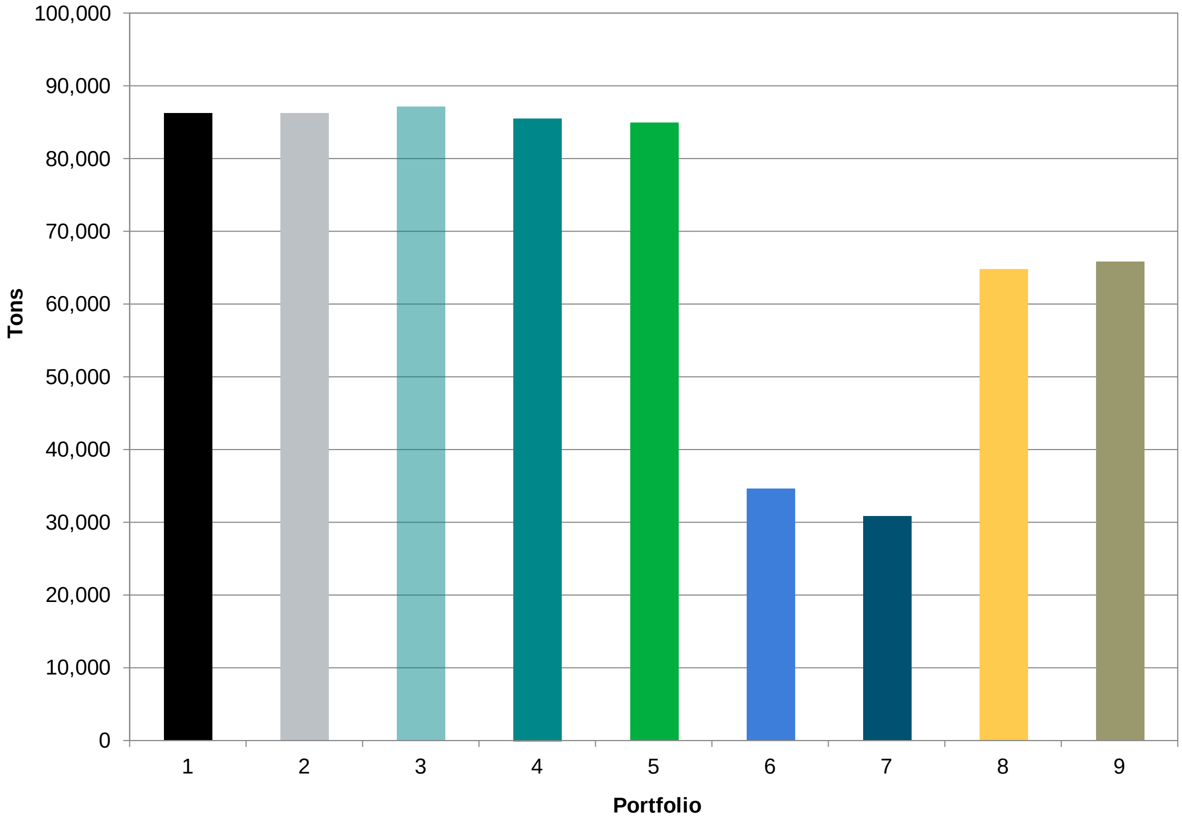

Figure 9.3 Total NO_x emissions for 2013–2032

SO_2 Emissions

Figure 9.4 shows the total SO_2 emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced SO_2 emissions. The reduced emissions are because a CCCT resource emits approximately 1 percent of the SO_2 per MWh that Idaho Power coal-fired generation resources emit on average.

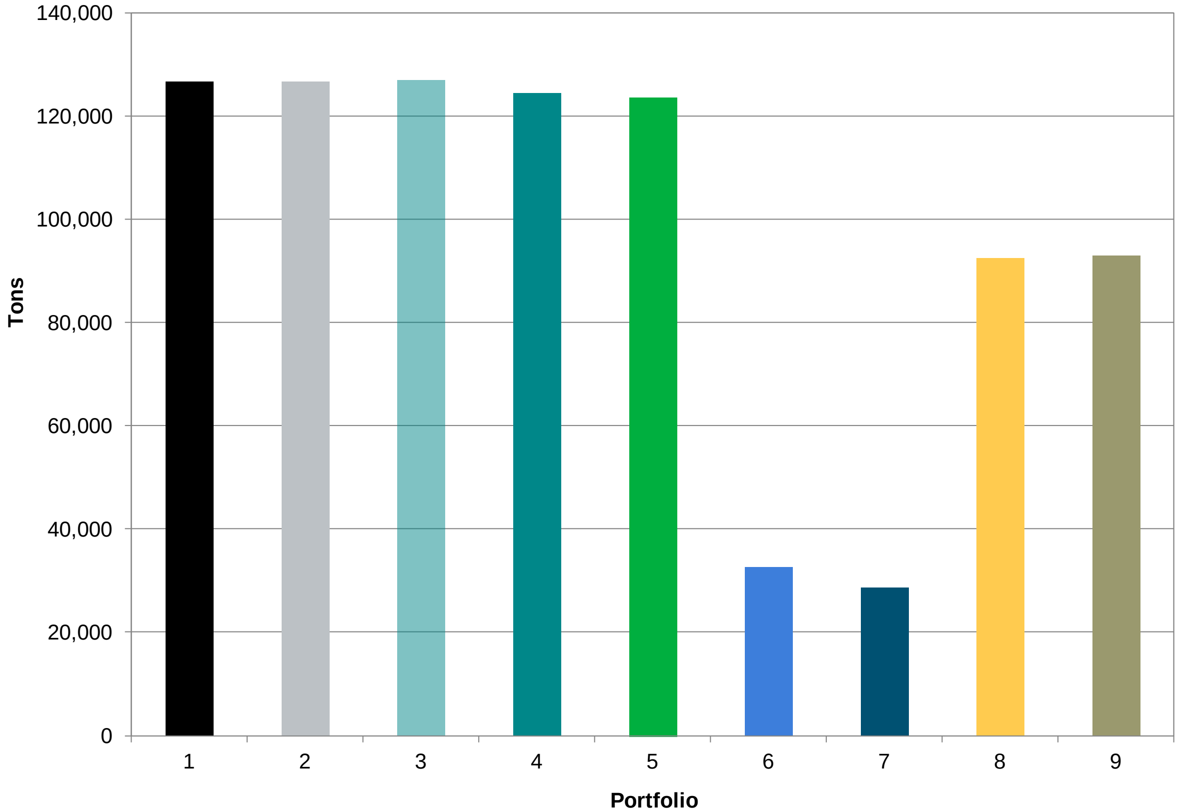

Figure 9.4 Total SO_2 emissions for 2013–2032

Hg Emissions

Figure 9.5 shows the total Hg emissions for each portfolio analyzed for the 20-year period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced Hg emissions. The reduced emissions are because CCCT resources do not have Hg emissions. Coal fuel contains traces of Hg.

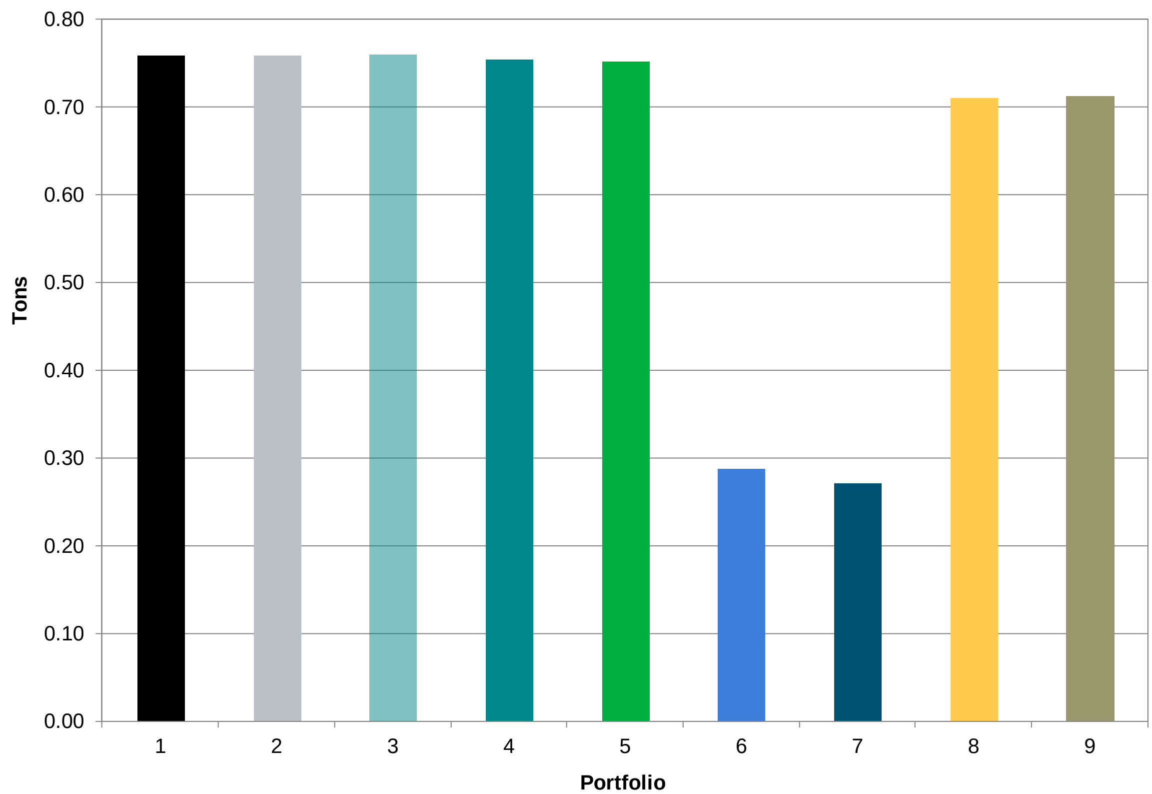

Figure 9.5 Total Hg emissions for 2013–2032

Stochastic Analysis

The stochastic analysis is an extension of the risk analysis of the resource alternatives presented in Chapter 7. The stochastic analysis simulates a variety of possible futures and calculates the resource portfolio performance in each of the futures.

Idaho Power identified the following four variables for the stochastic simulation:

1. *Natural gas price*—The natural gas price follows a log-normal distribution centered on the planning period forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2012. The serial correlation factor is 0.65.

2. *Customer load*—The customer load follows a normal distribution and is correlated with the Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

3. *Hydroelectric variability*—The hydroelectric variability follows a normal distribution. The Idaho Power-owned hydroelectric generation is serial correlated with the Pacific Northwest regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from the 1928 through 2009.

4. *Carbon adder*—Idaho Power and the IRP Advisory Council identified three carbon-adder scenarios: low, planning, and high. Idaho Power stratified the stochastic simulation, and one-third of the stochastic simulations were drawn from each of the three carbon-adder scenarios.

Idaho Power created a set of 102 simulations based on the four stochastic variables. Idaho Power then calculated the TRC of each of the nine resource portfolios for each of the 102 simulations using the Aurora model. Each simulation was reduced to one numerical value—the NPV of the total cost to meet the customer load over the 20-year planning period. Figure 9.6 shows the stochastic simulations.

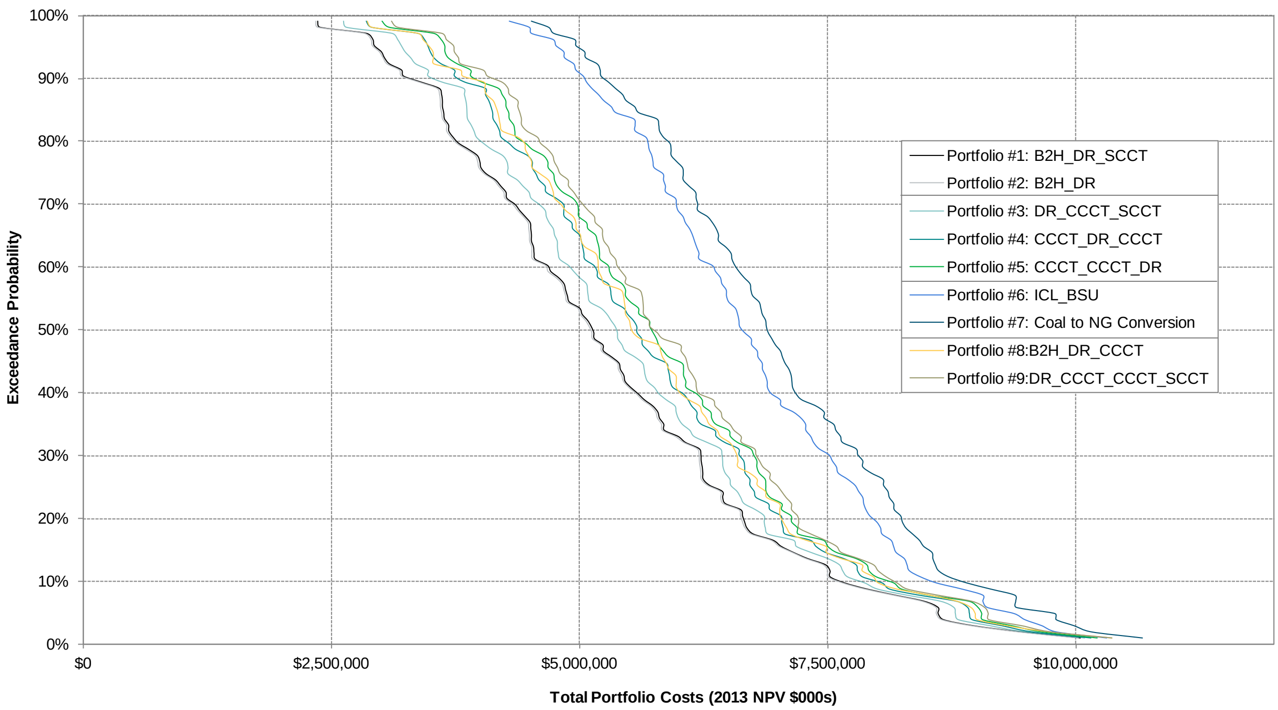

Figure 9.6 Portfolio stochastic analysis

Figure 9.6 shows the NPV of the portfolio cost on the horizontal axis and the exceedance probability on the vertical axis. The exceedance probability is the likelihood a resource portfolio will cost more than a certain amount. For example, in 50 percent of the simulations, resource portfolio 2 cost more than approximately $5.2 billion.

Resource portfolio 2, which relies on Boardman to Hemingway and Idaho Power's demand response programs to meet customer load, is the lowest-cost resource portfolio in all the simulations. The resource alternative analysis presented in Chapter 7 indicated that Northwest transmission, such as the Boardman to Hemingway transmission line, is the lowest-cost resource addition. The stochastic analysis confirms the cost-effectiveness of the Boardman to Hemingway line. In general, resource portfolios that contain the Boardman to Hemingway transmission line are less costly than the resource portfolios with alternatives to the Boardman to Hemingway line.

As expected, resource portfolios that replace generation resources cost more than resource portfolios that continue operations at the existing Idaho Power generation facilities. The resource portfolios replacing all of the coal generation have the highest cost and are represented by the two lines on the right side of the graph.

Carbon-Adder Analysis

During the IRP Advisory Council meetings in April and May, several IRP Advisory Council members questioned the effect of carbon-adder prices on Idaho Power's resource acquisition decisions. As described previously, the stochastic results demonstrated that resource portfolio 2 is the preferred resource portfolio. The IRP Advisory Council members' question was, "At what carbon adder does Idaho Power choose a different resource portfolio than resource portfolio 2?"

Idaho Power analyzed the IRP Advisory Council's question by increasing the price of the carbon adder beyond the values selected for the high-carbon scenario and extrapolated the trends in resource portfolio costs. The supplemental carbon analysis focuses on two of the resource portfolios: the preferred resource portfolio—resource portfolio 2—and the lowest-cost coal-retirement resource portfolio—resource portfolio 6. (Resource portfolio 6 was suggested by IRP Advisory Council members representing the ICL and BSU.) The results of the analysis are shown in Figure 9.7.

Figure 9.7 shows that at a carbon adder of approximately $45 per ton in 2018, the preferred resource portfolio would change from resource portfolio 2 to resource portfolio 6. (In 2018, the IRP high-carbon scenario has a value of $35 per ton.) The supplemental carbon analysis shows that sufficiently high carbon prices can affect Idaho Power resource acquisition decisions. Much lower carbon-adder values can affect the daily resource dispatch decisions under certain conditions as described previously in the Carbon Adder section.

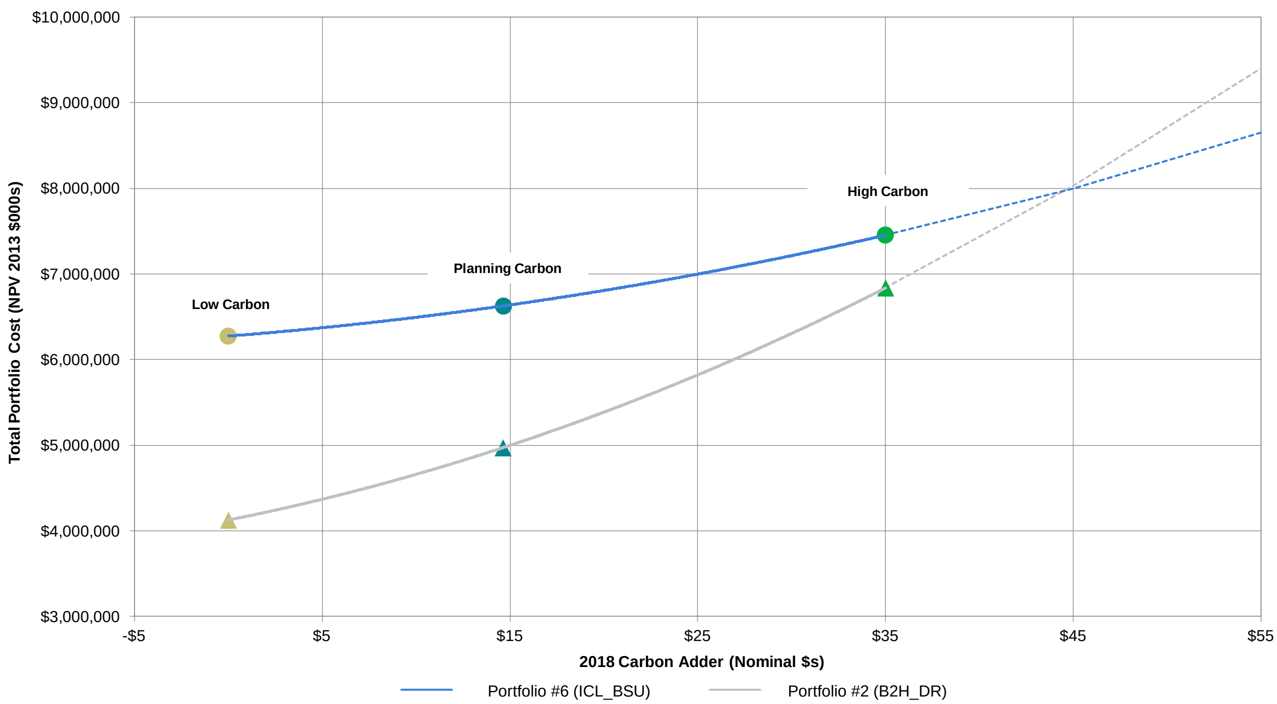

Figure 9.7 Stochastic-based carbon-adder tipping point

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 the 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 2013 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in 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. 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 NWPP. A 330-MW reserve margin is also roughly equivalent to a loss-of-load expectation (LOLE) of 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 9.3.

Table 9.3 Capacity planning margin

	July 13	July 14	July 15	July 16	July 17	July 18	July 19	July 20	July 21	July 22	July 23	July 24	July 25	July 26	July 27	July 28	July 29	July 30	July 31	July 32
Load and Resource Balance																				
Peak-Hour Forecast (50th%)	(3,189)	(3,245)	(3,294)	(3,335)	(3,387)	(3,437)	(3,489)	(3,544)	(3,601)	(3,651)	(3,701)	(3,748)	(3,790)	(3,836)	(3,888)	(3,936)	(3,984)	(4,045)	(4,097)	(4,147)
Existing Resources																				
Coal																				
Jim Bridger	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703
North Valmy	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Boardman	58	58	58	58	58	58	58	58	–	–	–	–	–	–	–	–	–	–	–	–
Coal Total	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**
Gas																				
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Gas Total	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Hydroelectric																				
Hydroelectric (50th%)—HCC	1,170	1,168	1,168	1,165	1,162	1,160	1,157	1,154	1,151	1,148	1,145	1,142	1,139	1,136	1,133	1,133	1,133	1,133	1,133	1,133
Hydroelectric (50th%)—Other	311	311	311	311	310	310	309	309	308	307	307	306	306	305	304	304	304	304	304	304
Shoshone Falls Upgrade (50th%)	–	–	–	–	–	–	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Shoshone–Bannock Water Lease	48	48	48	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hydroelectric Total (50th%)	**1,529**	**1,526**	**1,527**	**1,476**	**1,473**	**1,470**	**1,468**	**1,465**	**1,461**	**1,458**	**1,454**	**1,450**	**1,447**	**1,443**	**1,440**	**1,440**	**1,440**	**1,440**	**1,440**	**1,440**
CSPP (PURPA) Total	**177**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**
PPAs																				
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Clatskanie Exchange—Take	6	6	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Clatskanie Exchange—Return	0	0	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PPAs Total	**41**	**41**	**41**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**

Table 9.3 Capacity planning margin (continued)

	July 13	July 14	July 15	July 16	July 17	July 18	July 19	July 20	July 21	July 22	July 23	July 24	July 25	July 26	July 27	July 28	July 29	July 30	July 31	July 32
Firm Pacific Northwest Import Capability Total	194	237	237	237	237	237	237	237	290	237	237	237	237	237	237	237	237	237	237	237
Gas Peakers Total	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	**3,681**	**3,733**	**3,733**	**3,676**	**3,673**	**3,670**	**3,669**	**3,665**	**3,657**	**3,601**	**3,597**	**3,593**	**3,590**	**3,586**	**3,582**	**3,582**	**3,582**	**3,582**	**3,582**	**3,582**
Monthly Surplus/Deficit	**492**	**488**	**439**	**341**	**286**	**233**	**180**	**122**	**56**	**(50)**	**(104)**	**(155)**	**(201)**	**(250)**	**(306)**	**(354)**	**(402)**	**(462)**	**(515)**	**(564)**
2013 IRP DSM (Energy Efficiency)																				
Irrigation	3	6	8	10	11	13	15	17	20	22	26	29	33	38	43	48	54	56	58	61
Commercial	7	13	20	25	30	36	41	47	53	60	67	74	80	86	92	98	104	109	114	119
Residential	0	0	1	2	3	6	9	8	8	8	9	11	14	18	23	29	33	38	42	46
Total New DSM Peak Reduction	**10**	**20**	**29**	**37**	**45**	**55**	**65**	**72**	**80**	**91**	**101**	**114**	**127**	**142**	**158**	**175**	**191**	**202**	**214**	**226**
Remaining Monthly Surplus/Deficit	**502**	**507**	**468**	**377**	**331**	**288**	**244**	**193**	**137**	**41**	**(3)**	**(41)**	**(73)**	**(108)**	**(148)**	**(179)**	**(211)**	**(260)**	**(300)**	**(338)**
2013 IRP Resources																				
2016 Demand Response	–	–	–	150	150	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2018 Boardman to Hemingway	–	–	–	–	–	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2024 Demand Response	–	–	–	–	–	–	–	–	–	–	–	370	370	370	370	370	370	370	370	370
New Resource Subtotal	**0**	**0**	**0**	**150**	**150**	**500**	**500**	**500**	**500**	**500**	**500**	**870**	**870**	**870**	**870**	**870**	**870**	**870**	**870**	**870**
Remaining Monthly Surplus/Deficit	**502**	**507**	**468**	**527**	**481**	**788**	**744**	**693**	**637**	**541**	**497**	**829**	**797**	**762**	**722**	**691**	**659**	**610**	**570**	**532**
Planning Margin	**16%**	**16%**	**14%**	**16%**	**14%**	**23%**	**21%**	**20%**	**18%**	**15%**	**13%**	**22%**	**21%**	**20%**	**19%**	**18%**	**17%**	**15%**	**14%**	**13%**

Flexible Resource Needs Assessment

In Order No. 12-013 issued on January 19, 2012, as part of Docket No. UM 1461 on the "Investigation of Matters related to Electric Vehicle Charging," the OPUC adopted the following staff-proposed guidelines:

1. *Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.*

2. *Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.*

3. *Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.*

Idaho Power relies primarily on its hydroelectric system to meet reserve requirements. Increases in Idaho Power's reserve requirements due to load-growth projections can be adequately handled with the existing hydroelectric generation.

Changes in intermittent resources, such as wind generation, will be the primary driver of future reserve requirements. Idaho Power's *Wind Integration Study Report*[4] details the effects of adding additional wind capacity to the Idaho Power system. The balancing requirements for various levels of wind integration are documented along with an estimated cost for integration at those levels.

Idaho Power has reviewed the guidelines and the preferred resource portfolio—resource portfolio 2. Specifically, resource portfolio 2 proposed to add no new intermittent renewable generation over the 20-year planning horizon. Idaho Power does not forecast a significant increase in intermittent generation from PURPA or a significant increase in intermittent renewable generation from the customer programs. Idaho Power does not forecast a need to increase flexible capacity associated with implementing resource portfolio 2.

Resource portfolio 2 adds two resources—the Boardman to Hemingway transmission line and demand response programs. Resource portfolio 2 is not expected to increase the supply of flexible resources over the 20-year planning horizon.

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[4] The *Wind Integration Study Report* can be found on Idaho Power's website at: http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf

Idaho Power does not project a gap between demand and the supply of flexible capacity. Electric vehicles are not expected to significantly affect the Idaho Power load and resource balance over the 20-year planning horizon. The effect of electric vehicles over the 20-year planning period is described in *Appendix A—Sales and Load Forecast*.

Loss of Load Expectation

Idaho Power used a spreadsheet model[5] to calculate the LOLE for the nine portfolios identified in the 2013 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred portfolio. As mentioned in the previous section, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require the use of the transmission capacity. The 2013 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator and purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load for the 10 peak hours in a given year. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power chose to calculate a LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5 to 1 hour per year.

The results of the LOLE probability analysis are shown in Figure 9.8. Several portfolios result in a LOLE greater than two, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The LOLE in 2031 is high for many portfolios due to the number of high load days and the assumptions made for demand response (only available for 10 peak days). The results indicate that resource portfolios 1 and 2 perform well over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

[5] Based on Roy Billinton's *Power System Reliability Evaluation*, chapters 2 and 3. 1970.

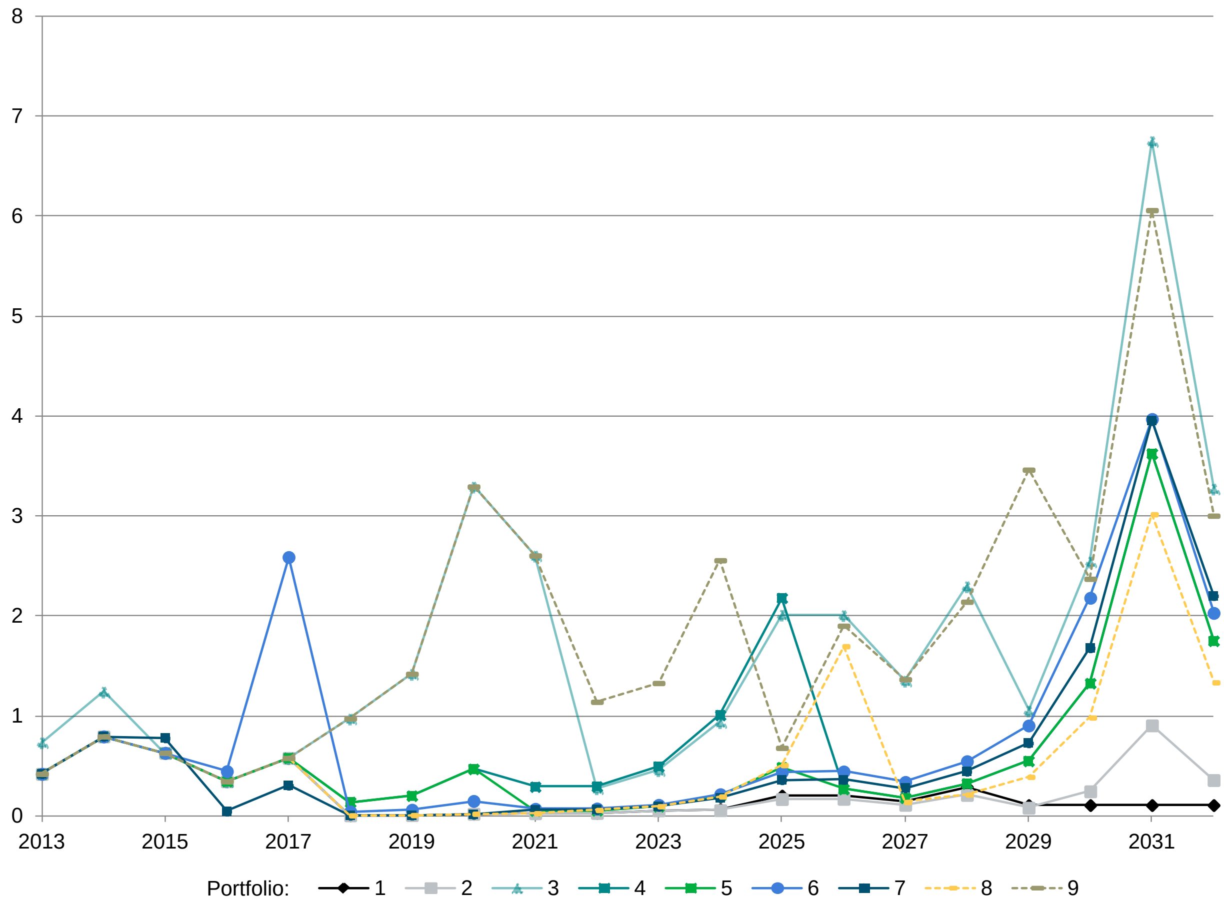

Figure 9.8 LOLE (hours per year)

Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In 2005, the NWPCC and the BPA created the Resource Adequacy Forum and asked the forum develop an adequacy standard for the Pacific Northwest regional power supply (Idaho Power participates as a member of the Resource Adequacy Forum). 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 the regional utilities when preparing their individual IRPs.

The NWPCC assesses the adequacy of the regional power supply annually. The latest assessment assumes the existing resources and conservation levels identified in the NWPCC 6th power plan, and the resource assessment shows the regional power supply to be slightly inadequate by 2017 (NWPCC document no. 2012-12). The adequacy assessment notes that adding 350 MW of dispatchable resource capacity brings the Pacific Northwest resource adequacy back within the 5 percent adequacy standard. The adequacy assessment indicates that the majority of potential problems are short-term capacity deficits. The regional resource assessment is available from the NWPCC at:

http://www.nwcouncil.org/energy/resource/2012-12/

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2013 IRP analysis indicates Idaho Power resource deficits occur in the summer months of June, July, August, and September. July is the most critical month for Idaho Power. The Northwest Regional Adequacy Assessment indicates that January, February, and, to a lesser extent, August are the most critical months for the overall Pacific Northwest region. The Boardman to Hemingway transmission line is a regional resource that will assist Idaho Power and the larger Pacific Northwest in addressing their opposing seasonal capacity deficits.

The Idaho Power resource planning process is consistent with the NWPCC resource adequacy studies. The Idaho Power stochastic analysis indicates that even under high load, high electricity prices, and low water conditions, resource portfolio 2 (containing the Boardman to Hemingway transmission project) is the lowest-cost resource alternative.

10. ACTION PLAN

Action Plan (2013–2032)

Resource portfolio 2 is the preferred resource portfolio. The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was mentioned as early as the 2000 IRP, and the upgrade was specifically identified in the 2006 IRP. Idaho Power continues efforts to acquire the necessary regulatory approvals and permits to begin construction. Construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018. The action plan to implement resource portfolio 2 is shown in Table 10.1.

Table 10.1 Portfolio 2 action plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings.
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings.
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology.
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology.
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW.
2018	Boardman to Hemingway	Transmission line complete and in service.
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031.

Idaho Power continues efforts to acquire the necessary regulatory approvals and permits for the Gateway West project. As discussed in Chapter 6, Gateway West will relieve transmission constraints and provide the option to locate future generation resources east of the Treasure Valley load center.

For the purpose of this resource plan, the company’s demand response programs are assumed to be used throughout the planning period to meet resource needs. Idaho Power expects to use up to 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission line in 2018. Idaho Power applied demand response in approximate 50-MW steps for the 2013 IRP. In the analysis, Idaho Power tailored the level of demand response to the identified deficit. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The level of demand response projected for 2016 was approximately 100 MW and approximately 150 MW in 2017. Idaho Power plans to have a demand response capacity available beginning in 2024 of up to approximately 370 MW by 2031. Like the 2016 to 2017 time period, demand response for later time periods was applied in 50-MW increments for the resource portfolio analysis. The level of demand response capacity available will be based on the deficits identified through the IRP process or based on operational needs identified between IRP cycles.

The Boardman to Hemingway transmission line is a significant interstate construction project with federal, state, and local permitting and line routing issues. In addition, the project has multiple business partners, which further complicates project management and scheduling. Idaho Power intends to use the demand response programs to adapt to schedule variations that may occur on the Boardman to Hemingway project.

Resource portfolio 2—the preferred resource portfolio—includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to their installation and operation. The approximate financial commitment dates are identified in the action plan.

Idaho Power can develop and own generation assets, rely on PPA and market purchases to supply the electricity needs of its customers, or use a combination of the two ownership strategies. Idaho Power expects to continue participating in the regional power market and enter into mid-term and long-term PPAs. However, when pursuing PPAs, Idaho Power must be mindful of imputed debt and its potential impact on Idaho Power's credit rating. In the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate-of-return advantages inherent in a regulated electric utility.

Conclusion

The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission project has outperformed the other resource portfolios in the 2013 IRP. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.

Wild horses near the Hemingway Substation.

The 2013 IRP confirms that the Boardman to Hemingway transmission line is a very cost-effective resource. The Resource Alternatives Analysis section of the 2013 IRP indicates that the Boardman to Hemingway line is more cost effective than the other supply-side resources studied. Chapter 9 of the 2013 IRP indicates that resource portfolios containing the Boardman to

Hemingway line are more cost effective than resource portfolios containing alternatives to the Boardman to Hemingway line.

Idaho Power treated the Boardman to Hemingway Transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates that it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

The company's demand response programs will be used throughout the planning period to meet resource needs. The level of demand response capacity available will be based on the deficits identified through the IRP process or on operational needs identified between IRP cycles. The demand response programs may also be used to adapt to schedule variations that may occur on the Boardman to Hemingway transmission project.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRP Advisory Council members and the public for their contributions to the 2013 IRP. The IRP Advisory Council discussed many technical aspects of the 2013 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to Idaho Power facilities. Idaho Power's resource plan is better because of the contributions from the IRP Advisory Council members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates that the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

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